

New Brunswick System Operator  
Exploitant du réseau du Nouveau-Brunswick



# **State of the Market Report**

April 2007 to March 2008

## Executive Summary

The State of the Market Report is produced in accordance with the New Brunswick Electricity Market Rules. This report covering the fiscal period April 1, 2007 to March 31, 2008 provides a summary of the state of the New Brunswick Electricity Market indicating the New Brunswick System Operator (“NBSO”) Board’s general assessment as to the state of competition and efficiency of the electricity market.

While the physical bilateral market design implemented October 1, 2004 is still viewed as an efficient and appropriate model for New Brunswick and the Maritimes Area, the integration of non dispatchable generation may require future market design changes. A bilateral market by nature will not result in the rapid development of a fully competitive market. The level of competition will gradually increase as new generation is required to meet load growth, as existing plants retire, as native contestable load leaves standard service and as export merchant plants locate in NB. The level of activity by native load customers was not expected to be large considering the objective of the Energy Policy of 2001 to take a “deliberate and controlled” approach to the introduction of competition.

The complete lack of native load activity, however, is attributable to the rise of wholesale market prices relative to regulated rates and a lack of clarity regarding exit fees and partial service. The latter two are viewed by the NBSO as barriers that should be addressed.

While low domestic load growth and rising wholesale prices relative to regulated rates have reduced the potential for greater competition, there are offsetting factors that will increase the potential for competition in the future. These include the possibility of replacing high cost fossil generation with new non-fossil generation, an increase in the demand for renewable energy, and the potential for merchant export facilities to meet electricity load growth in New England. As the New Brunswick market is relatively small, medium-term development will likely be driven by export markets.

The number of registered market participants continues to increase. This is a positive development as it supports greater competition.

The NBSO is encouraging the development of a competitive supply of balancing energy and capacity-based ancillary services market. While progress has been slow, the NBSO is taking steps to address this. External transmission requirements are a barrier which is being discussed with adjacent transmission providers. Market rule changes have also been implemented in response to feedback received from potential market participants.

The expectation of substantial amounts of wind power generation in the region has led to a focus on wind related issues. A wind power integration study published by the NBSO in April of 2007 identifies the need for tariff and market rule changes as well as improved regional cooperation. Greater cooperation will enhance the ability of the regional system to accommodate wind power through added flexibility and reduce the variability and forecast error of total wind power production. Competitive procurement of balancing energy, regulation, and load following is important to the successful integration of wind power in the region. Enhanced competitiveness in the procurement of these services will continue to be a priority for NBSO.

With respect to market compliance, the Board is satisfied that non-compliance issues are being addressed appropriately. Implementation of the various components of the NBSO assurance plan will continue in order to further monitor compliance of market participants, transmitters, and the system operator, as well as the effectiveness of the market. Market monitoring is a responsibility that is shared with the New Brunswick Energy and Utilities Board (“EUB”). NBSO intends to work closely with the EUB to monitor the functioning of the market and to make ongoing enhancements to both the market design and the monitoring process as required.

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## **1.0 Introduction**

This second State of the Market Report is published by the New Brunswick System Operator (“NBSO”) in response to its market function obligations. It covers the period of April 1, 2007 to March 31, 2008. While the first report covered the period of October 1, 2004 to March 31, 2007, future reports will be published on an annual basis.

The report provides the NBSO Board’s general assessment as to the state of competition and efficiency of the market with a look forward at future market development. It summarizes the state of the market, describes market monitoring activities and outlines the changes undertaken by the NBSO to improve market design. Complaints investigations undertaken during the fiscal year are also included.

In addition to being responsible for the functioning of the electricity market, the NBSO must also ensure the reliable operation of the New Brunswick electric power system. The market function includes tariff design, market rule design, administration, settlement and market monitoring.

## 2.0 State of the Market

### 2.1 Market Design

The New Brunswick Electricity market has been designed as a physical bilateral market built on the foundation of a Federal Energy Regulatory Commission (“FERC”) Order 888 compatible tariff. NBSO now intends to establish compatibility with FERC’s more recent Order 890, 890A and 890B, which preserve the basic components of the Order 888 *Pro Forma* tariff. Additional modifications may be required to facilitate renewable generation technologies and the need for greater efficiencies in the use of the transmission system.

With Northern Maine, Nova Scotia, and Prince Edward Island only connected electrically to the remainder of North America via New Brunswick, the New Brunswick market, in many ways, acts as a wholesale market for the region.

The basic physical bilateral market design is compatible with the New Brunswick “deliberate and controlled” introduction of a competitive market and also with the existence of a *de facto* regional wholesale market with a small number of players in the region, and with most having native loads. Load-serving entities contract with suppliers for the energy and capacity necessary to serve their load and maintain system reliability. These transactions are scheduled with NBSO as the independent system operator responsible for the Open Access Transmission Tariff and Market Rules governing the use of the transmission system in New Brunswick. NBSO creates an optimized security-constrained economic dispatch of generation and loads using bids received from those resources.

On a planning basis, NBSO publishes an annual 10-Year Assessment of the Adequacy of Generation and Transmission Facilities (“10-Year Assessment”) report. In keeping with the intent of some aspects of FERC Order 890, the 10-Year Assessment report

now also examines regional transmission needs. Expansion of the scope of the 10-Year Assessment beyond reliability to include overall system needs inclusive of economics is under consideration. The drivers for such an expansion of scope include a rapid and significant increase in the cost of fossil fuels, environmental constraints, and industry recognition of a degree of centralized planning. The 10-year timeframe may also be increased based on the fact that some generation investments require lead times of up to a decade, and the fact that very long-term environmental targets are emerging.

Balancing energy and capacity-based ancillary services have been identified as having potential for competitive procurement and emphasis has been placed on establishing competition in NBSO's procurement of these services. This is consistent with policy, market design, and a regulatory framework that encourages competitive procurement of ancillary services.

## **2.2 Market Power**

Market power is the ability of a dominant market participant to engage in activities that reduce or prevent market competition. In the NBSO's role to develop a competitive market the presence of market power is not an issue, but the practice and effect of anti-competition behaviours are.

In its day-to-day monitoring of the market the NBSO has not suspected or received any complaints of market power abuse. The NBSO will continue to monitor for signs of anti competition behaviour by market participants

It is important to note that the design of the New Brunswick physical bilateral market is more resistant to market power abuse than other designs such as pure pool arrangements. This is especially appropriate for the Maritimes context with such a small number of active wholesale market suppliers. In a bilateral market, pricing decisions are made over longer time frames and there is less ability to influence price.

The only real time market in New Brunswick is the differences between bilaterally scheduled production and the actual production which is settled by the NBSO. To mitigate market power further, the prices used for the settlement of the difference between dispatched production and the bilaterally scheduled production is settled at the price bid by the supplier, rather than at a marginal market clearing price, which would be equal to or higher than the bid price. The New Brunswick market also uses the same bid prices for both increases and decreases in generation, further reducing the likelihood that prices would be set either higher or lower than cost (inclusive of opportunity cost).

Another mitigating factor is that the rates offered to contestable standard service customers are regulated to ensure that they are just and reasonable. As a result the ability of the standard service supplier to raise prices to increase profits is greatly reduced.

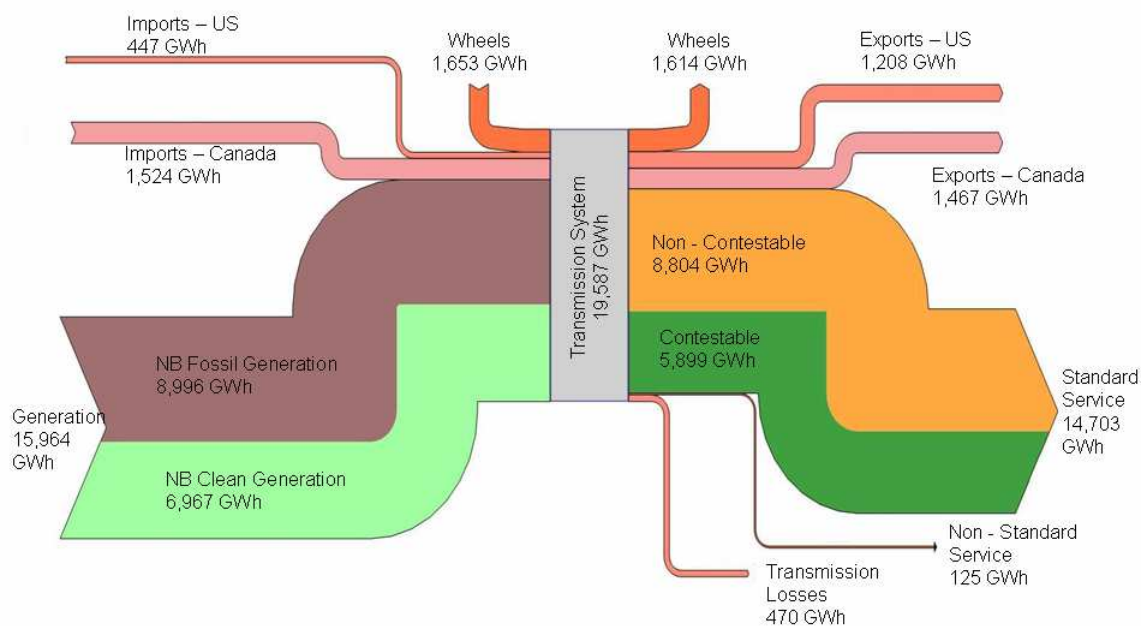
While the ability to exercise market power to affect prices is low, the ability to prevent market entry does exist. This effectively lessens competition. A dominant player with broad interests in distribution, transmission and generation could undertake practices to prevent entry of new players. Examples of such practices include cross subsidization of rates for contestable customers, locking customers into long term contracts, buying existing non-utility plants, not procuring new supply on a competitive basis, and hoarding transmission. It is important to note that the existence of these practices does not necessarily mean that there was intent to lessen competition. Some of the actions are taken to improve efficiency, which is in the best interest of consumers.

### **2.3 Bilateral Market Energy Flows**

The scheduled market flows for April 2007 to March 2008 are shown in Figure 1 to illustrate the volumes of injections into and withdrawals out of the transmission system. The widths of the lines on the chart are proportional to the flow volumes. The information is useful in gaining a perspective on the level and nature of activity.

Scheduled injections into the transmission system are dominated by New Brunswick based generation which makes up 82 % of the total. Imports account for 10% and the remaining injections are flows wheeled through the system. The figure also shows the split between clean and fossil generation with clean generation making up 45% of the provincial mix. It should be noted that industrial self generation is not included in the figure as it is not scheduled on the transmission system. With increasing fossil prices and increased demand for clean generation the mix of clean vs. fossil is expected to change over the mid-term.

**Figure 1**  
**Bilateral Market Transactions**  
**April 2007 to March 2008**



On the withdrawal side of Figure 1, New Brunswick load served by the standard service supplier is the dominant category making up 75% of the total. The remaining 25% is made up of wheels (8%), exports (14%), New Brunswick load not provided by the standard service supplier (0.5%) and scheduled transmission losses (2.5%). New Brunswick load includes both contestable and non-contestable loads. Contestable load is use by industrial and municipal customers in New Brunswick who have an option of

procuring power from a supplier other than the standard service provider, NB Power Distribution & Customer Services Corporation (“NB Power Disco”). It is worth noting that 40% of New Brunswick’s electrical consumption could be provided by any supplier.

Compared to the last fiscal period there has been a 63% increase in electricity wheeled through the New Brunswick transmission system. Imports and exports have increased from both Canada and the United States while generation injections declined. As exports have increased the generation decline was likely the result of more imports and decreased load requirements. Of particular note was a 5% decrease in the contestable New Brunswick load which is likely due to recent mill closures. As New Brunswick electricity prices are susceptible to high fossil prices it can be expected that standard service rates will increase which may lead to further loss of load either through closures or reduced consumption (resulting from production reduction, conservation, or energy efficiency). Higher standard service rates may spur interest among contestable customers to look at alternatives.

## **2.4 Open Access Transmission**

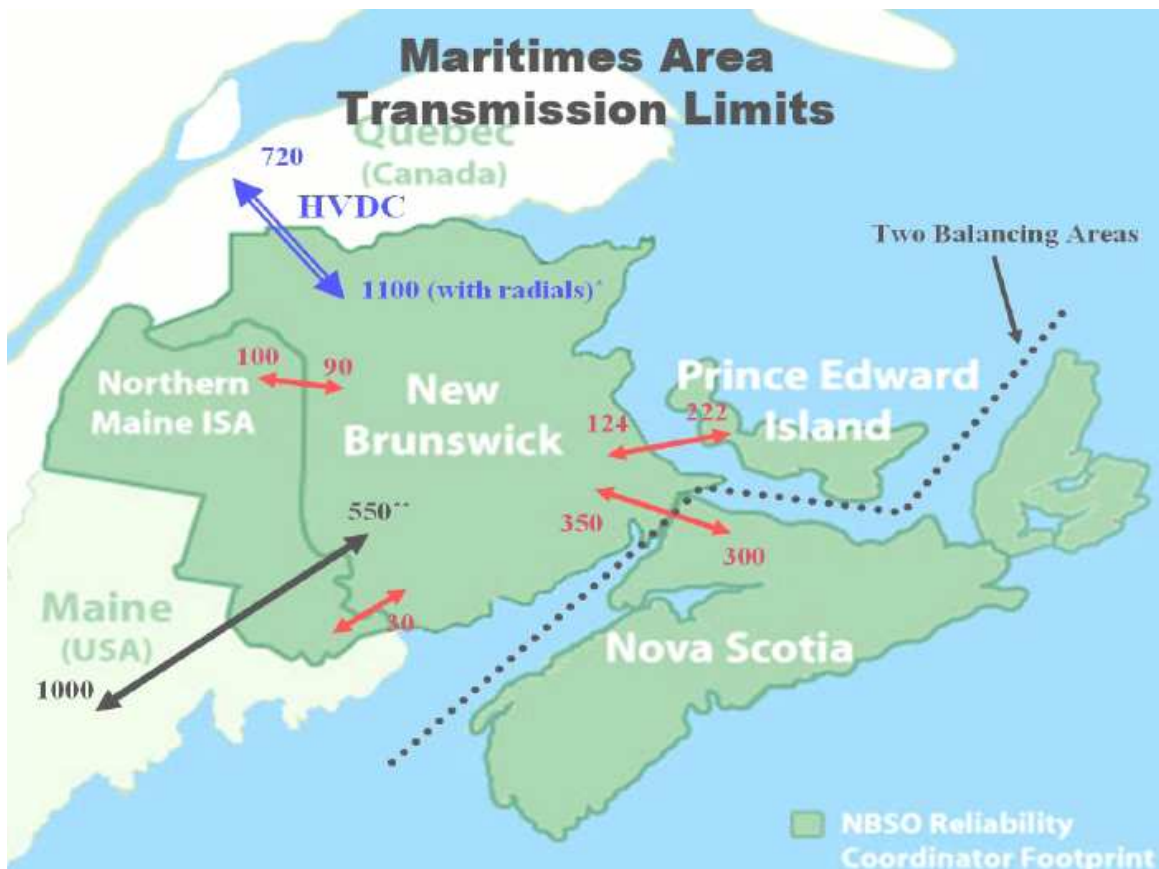
Critical to the operation of the New Brunswick market is non-discriminatory open access to the transmission system which is the connection between buyers and sellers. An independent system operator provides confidence to market participants that they are being treated fairly.

Figure 2 shows the highly interconnected nature of the New Brunswick transmission system. The existence of multiple interconnects with adjacent systems increases the relevance to New Brunswick and the region of maintaining open access to the New Brunswick transmission system.

In the case of a relatively new market structure an indicator of development is the number of customers accessing transmission services. As the number of customers increase so does the potential for greater competition.

There are two basic transmission services, network and point to point. Network service is used by customers who inject and withdraw from the system without specifying the location, time or amount of the injection or withdrawal. NB Power Disco serves a large load from many points and is an example of a network services customer. Point-to-point service is used by a customer to transmit a specific amount of energy or capacity from one point to another point. An example would be a customer that wheels electricity into and out of New Brunswick.

**Figure 2**  
**New Brunswick's Transmission Interconnections**



At the start of the market opening, NB Power Disco was the only Network Service Customer. Since that time, loads for Perth-Andover (January 1, 2005) and Eastern Maine Electric Cooperative (December 1, 2005) have become Network Service Customers.

The number of transmission customers taking point-to-point transmission service in the first month of market operations in October of 2004 was two. This has increased to six in March of 2007 and nine in March of 2008.

**Figure 3**  
**Transmission Service Purchases**  
**(Equivalent Monthly MW)<sup>1</sup>**

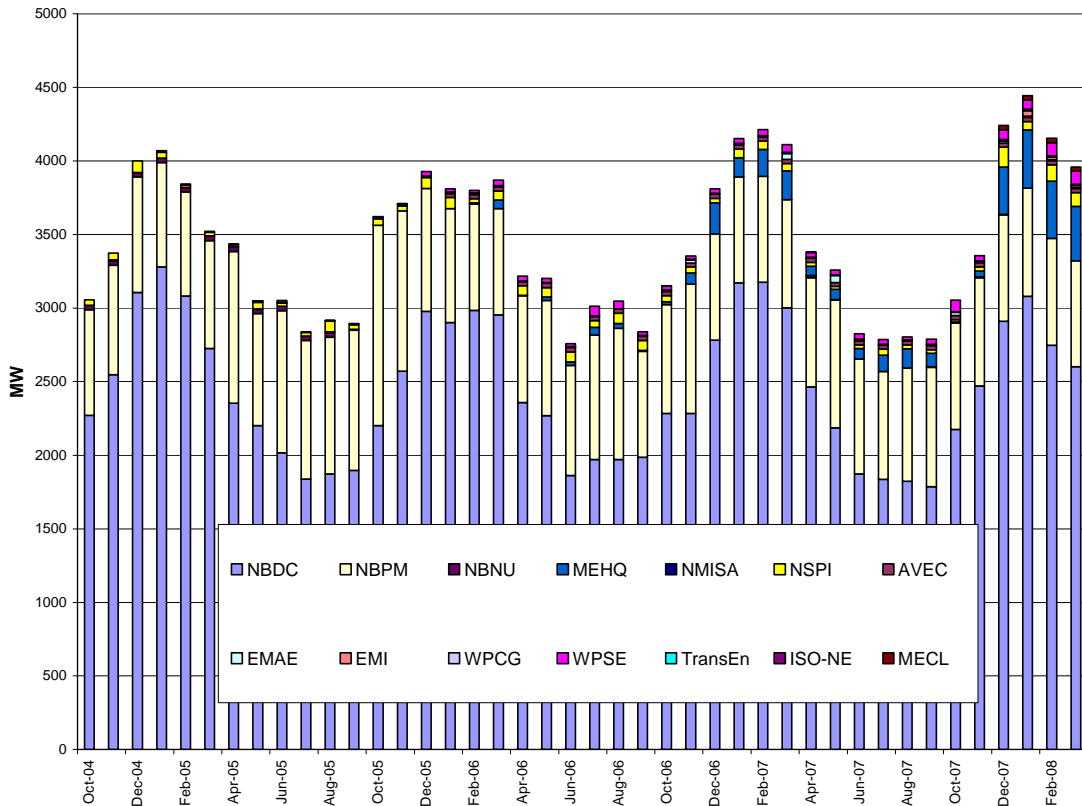


Figure 3 shows each company's monthly transmission service purchases in MW with all point-to-point reservations converted to monthly equivalents.<sup>2</sup> This figure not only

<sup>1</sup> The full names of those entities that purchased transmission are identified in an appendix to this report.

shows the increase in the number of parties purchasing transmission services, but also the variability of the transmission service sales. For network service in New Brunswick, the variability is heavily affected in the winter by electric heating load while point-to-point service sales are affected by regional market conditions (Quebec, New England, Nova Scotia, etc).

The potential for additional transmission customers is high with New Brunswick's development of the Energy Hub concept that promotes the province as a major energy supplier to external markets. There has been a marked increase in the interest in wind power projects for both export and in-province demand created, at least in part, by renewable portfolio standards. Additionally, the potential transmission routing through New Brunswick of the Lower Churchill hydro project in Labrador will bring more opportunities.

The commissioning of the International Power Line/Northeast Reliability Interconnect ("IPL/NRI")<sup>3</sup> increases New Brunswick's transfer capability into and out of New England. The pending increase in commercial export and import capacities as a result of the new line will further support potential export development projects in New Brunswick and provide New Brunswick loads with greater choice.

While the existing New Brunswick transmission system will support generation development, the export of large volumes of power, as implied in the Energy Hub concept, will require additional transmission within New Brunswick, across interfaces, and on adjacent systems. This requirement leads to a need for various technical and economic studies of appropriate transmission builds. A review of the overall approach to transmission investment and usage may be necessary given the magnitude of the potential generation, the number of generation project proponents, the non-dispatchable nature of some of the proposed generation, and the magnitude of the transmission

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<sup>2</sup> The MW for reservations of on-peak products are scaled up to reflect the premium posted rates for those services.

<sup>3</sup> International Power Line/Northeast Reliability Interconnect, a 345 kV transmission line between Lepreau, New Brunswick and Orrington, Maine.

investments. Table1 illustrates the various approaches that can be considered in such a review.

**Table 1**  
**Treatment of Transmission Interfaces**  
**(i.e. Ties Between Markets)**

	<b>Standard Market Design (SMD)</b> <b>(e.g. ISO-NE, NY)</b>	<b>Order 888/889/890</b> <b>(e.g. NB, NS, PEI)</b>	<b>Denmark</b> <b>(new model)</b>	<b>Pure Merchant</b>
<b>Congestion management</b>	No reservations (i.e. physical rights), but financial congestion rights available through auction (typically <=5years).	Reservations providing physical rights for delivery of energy (Long-Term Firm { no limit on duration, plus renewal rights }, Short Term Firm, and Non-Firm)	No physical rights. Dispatch cheapest bids.	May be physical rights. Actual models vary.
<b>Transmission Investment</b>	Incumbent utilities or other transmission owners (may be private or not)	Incumbent utilities or other transmission owners (may be private or not)	Transmission System Owner (Government)	Private companies
<b>Transmission Cost Recovery for Upgrades of Interfaces Between Markets (Shared Transmission Network)</b>	Cost is rolled into total tariff revenue requirement. The <u>total</u> requirement is paid for by all load and exports.  In some models there is essentially no charge for exports (e.g. Ontario). In some designs reciprocity agreements waive charges on inter-market flows in either direction.	Revenues from reservations go to the transmission owner, the reserving party pays for what they reserve whether they use it or not.	The “real-time” economic value of the interface is split 50/50 between the two loads in the two markets.	Auctioning of use in real-time (or may allow auctioning for longer-term rights)
<b>Risk on usage</b>	The <u>load</u> carries the risk on the volume of usage. If no-one uses the interface, then tariff rates will go up for the load. If the usage is high, then the rates will go down.  If there are no charges for the usage of the interface, then the load pays the cost whether the interface gets used or not.	Risk is split between load and long-term export reservation holders, depending on the volume of reservations. If long-term reservation quantity exceeds x, then the reservations reduce what load will have to pay on existing transmission assets. If volume equals x, then the reservation holders pay the full cost of the interface. If the volume is less than x, then the load makes up the difference on the cost of the interface.	Load	Transmission Owner

NBSO's 10-Year Assessment of the Adequacy of Generation and Transmission Facilities<sup>4</sup> document provides a perspective on the need for transmission upgrades and some insight into work that is being undertaken to address those needs.

## **2.5 Market Participation and Facility Registration**

Since the opening of the market there have been positive signs as the number of both accredited and active market participants has increased.

### **Generation Facilities**

All of the existing generation facilities other than the Point Lepreau nuclear generation station and Bayside are registered in the market by NB Power Generation Corporation ("NB Power Genco"). This includes a number of independently owned facilities, one of which was recently purchased by NB Power Genco. The 10.8 MW Great Falls Hydro facility, now known as Nepisiguit Falls Generating Station was acquired by NB Power Genco at the end of June, 2007. The Point Lepreau Generation Station is registered by the NB Power Nuclear Corporation. A list of the existing generators in New Brunswick is available in the NBSO 10-Year Assessment.

New generators in New Brunswick have the ability to serve domestic market load or to export power out of New Brunswick to serve other markets. While no new generation facilities have been built in New Brunswick since the opening of the market the main drivers for new generation will be:

- New Brunswick's Electricity from Renewables regulation;
- Replacement of high cost fossil generation in New Brunswick;
- Pending greenhouse gas regulations;
- Significant load growth in New England;
- New England state renewable portfolio standards; and
- New Brunswick contestable load leaving standard service supply.

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<sup>4</sup> [http://www.nbso.ca/Public/\\_private/10-year%20Assessment%202008.pdf](http://www.nbso.ca/Public/_private/10-year%20Assessment%202008.pdf)

Load growth in New Brunswick is not expected to be a driver for new generation. In fact, with recent closures of large industrial facilities, recent short term load growth has been negative. The demand for renewable generation may also spur the redevelopment of existing hydro sites such as was done at the St. George Hydro site. This facility is EcoLogo certified and able to supply the renewable market.

One of New Brunswick's key development advantages is the ability to site new generation. This is evidenced by public support for the refurbishment of the Point Lepreau nuclear generation station, the construction of the Liquefied Natural Gas facility and most notably the election of a political party that included new nuclear development in its platform. With several major projects, the workforce is growing to support current and future projects. Geographically the province is close to major loads in New England and the Maritimes and has a strong transmission system that is open for access. Ice free deep water ports provide access to fuels and the potential for natural disasters such as hurricanes and earthquakes is low. New Brunswick's indigenous energy sources include biomass, small amounts of natural gas, and a world class wind regime. New Brunswick's energy hub strategy coupled with a small government that responds quickly to developer needs also supports the ability to site new generation.

A strong indicator of the potential for new generation facilities in New Brunswick is the number of initiated system impact studies. The system impact study is one of the early steps required in the transmission connection process. While there is no guarantee that these projects will be completed they are indicative of the number of developers who are serious about their potential projects.

Table 2 illustrates the system impact studies for generation projects that were initiated during the reporting period.

It was a very active year with 11 projects initiating system impact studies totaling 1,279 MW of generation. Of interest is the fact that all of the projects were for the development of wind. The key drivers for wind include the requirement for NB Power

Disco to meet the provincial renewable electricity targets, the growing demand for electricity in the New England market, the New England renewable energy credit market and the increasingly favourable economics of wind.

**Table 2**  
**Initiated System Impact Studies – Generation Projects**  
**April 2007 to March 2008**

Name	Location	Size (MW)	Company
Caribou 99 MW Wind Project	Caribou, NB	99	Ventus Energy Inc
Aulac Wind Farm	Aulac, NB	300	Acciona Wind Energy Canada Inc.
Lamèque Wind farm	Lamèque, NB	50	Acciona Wind Energy Canada Inc.
McAdam Wind Farm	McAdam, NB	52	FPLE Canadian Wind, ULC
St. George South Wind Farm	Saint George, NB	204	FPLE Canadian Wind, ULC
Murray Corner Wind Farm	Murray Corner, NB	99	SkyPower Corp.
Anse-Bleue Wind Farm	Anse-Bleue, NB	99	SkyPower Corp.
Escuminac Wind Farm	Escuminac, NB	104	SkyPower Corp.
Mann Siding Wind Farm	St. Quentin, NB	150	Shear Wind Inc.
Caribou Mines Wind Farm Phase II	Caribou Mines, NB	101	Ventus Energy Inc.
Grand Manan Wind Project	Grand Manan, NB	21	Dark Harbour Wind Inc.

With a number of wind projects in various stages of development, it is expected that one or more generation facilities will be registered by a market participant other than NB Power within the next year or two. The initial wind projects in New Brunswick will be under contract with NB Power Disco for some or all of their output. Other wind power production will most likely be exported, with New England as a probable destination.

With a growing interest in wind, the NBSO's responsibilities require it to respond to the associated need for system planning, policy decisions, interconnection, integration, etc. A consulting firm from Denmark, Ea Energy Analyses ("EA"), was engaged in the fall of 2007 to provide guidance on wind power development, interconnection, and integration. They reviewed the situation in New Brunswick and surrounding jurisdictions, commented on work that NBSO had already performed in the topic area, shared their knowledge and held a workshop with key stakeholders. This project led to a Phase II engagement sponsored by NBSO and the New Brunswick Department of Energy. In this Phase II project EA is to perform scenario modeling of the regional market to assess the economic feasibility of large scale wind power development. EA will transfer the model to NBSO, host a visit to Denmark by New Brunswick representatives, provide a roadmap on wind power development, and comment on NBSO's role therein. The Phase II project is due to be completed by the end of the first quarter of 2008/09.

Upon completion, these two projects will have significantly advanced the NBSO's understanding of the topic and will help facilitate planning for ongoing work.

In addition to wind, the potential exists for other generation facilities to be built and possibly registered by a market participant other than NB Power Genco . Such projects could include additional nuclear units at Point Lepreau, cogeneration at the LNG facility, and biomass generation.

The economics of the current market conditions appear to be the main impediment to new generation development in New Brunswick to serve New Brunswick load. Sufficient capacity exists to meet the short-term needs and so the short-term economics suggest that the full cost of new generation needs to be less than the variable costs for existing generation. With high fossil fuel prices a longer-term view may suggest that new generation will be built to displace fossil generation. Continuation of high oil, natural gas, and coal prices and the lack of a low-cost alternative fuel, combined with

opportunities for cost-effective efficient new generation, may very well lead to favourable economics for new generation.

The following items have also been identified as potential impediments to new generation being built:

- The existence of what is effectively a single buyer market for local use.<sup>5</sup>
- Perceptions of limited transmission access to the New England market.
- The complexities of the processes involved (e.g. connection process, connection agreements, tariffs, market rules, and standard service rates, terms and conditions) and the lack of consultants, marketers, and aggregators that understand the details of those processes.
- The various areas of uncertainty in any business case for the construction of a new generator (e.g. greenhouse gas regulations/taxes, renewable energy credit markets, fuel prices, lack of a long-term contract).
- The lack of New Brunswick demand and new capacity requirements as a result of relatively low domestic load growth coupled with plans to develop new renewable generation to meet the targets set out in the *Electricity from Renewables Regulation*<sup>6</sup> and the effect of Efficiency NB's programs to reduce domestic electricity use.

## **Load Facilities**

A deliberate and controlled approach was used by the Province of New Brunswick in establishing the market as prescribed in the *White Paper New Brunswick Energy Policy* of 2001. Customers were provided protections against rate shock or changes in risk levels that might otherwise have occurred with the introduction of the market under more aggressive market designs. This protection was provided through standard service supply that continues to access heritage generation assets at prices based on their embedded costs, as opposed to exposing those customers to market prices. While distribution level retail customers must remain on standard service, municipal utilities

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<sup>5</sup> While approximately 40 customers directly connected to the New Brunswick transmission system have the right to buy from an alternative supplier, they have not done so to date as discussed herein.

<sup>6</sup> <http://www.gnb.ca/0062/PDF-regs/2006-58.pdf>

and large industry connected to the transmission system have the choice to buy electricity from an alternative supplier.

During the transition to market, market prices for electric energy increased significantly as fuel prices (oil, coal, and natural gas) increased. Oil fired generation is typically on the margin in New Brunswick, and natural gas is typically on the margin in New England. Hydro-Québec's prices on exports are presumably driven by the regional value of energy (i.e. they are motivated to sell to the highest bidder). As a result, rather than being attracted away from standard service rates to marginal cost pricing in the marketplace, contestable customers became mindful of the risk of higher electricity prices, similar to what they were experiencing first-hand on purchases of oil, coal, and/or natural gas.

While standard service rates have increased sharply over the last several years their rise has been tempered in consideration of rate shock impact. The New Brunswick Energy and Utilities Board (EUB) recent rate decision kept the standard service supplier's interest coverage ratios low to minimize rate impact. A lower interest coverage ratio has a compounding effect as it also lowers payments in lieu of taxes. The EUB also adopted the principle of gradualism and avoidance of rate shock in addressing revenue to cost ratios for customers outside the 0.95 to 1.05 band. These actions keep standard service rates lower, but, decrease the likelihood of a customer leaving standard services.

In addition to the favorable regulated rates relative to current market rates, the following issues have been identified as hindrances to customers leaving standard service.

- The fact that the magnitude of the exit fee is not known. The exit fee is a fee that a customer would pay the standard service supplier should that customer choose to buy from a new supplier. The intent of the fee is to keep remaining standard service customers whole. Recent changes to the *Electricity Act* allowing for an EUB hearing on establishing the methodology for the determination of the exit fee without an actual application to exit should

partially alleviate some uncertainties. Key to the exit fee determination will be the costs that NB Power Disco avoids as a result of load loss. Further discussion on the exit fee and the conditions that must exist to support a business case for load to leave standard service can be found in Appendix 2.

- The uncertainty of how standard service billing, energy scheduling, and settlement would be handled, should a standard service customer choose to supply part of its load from an alternative supplier.

For customers that do leave standard service some risk is mitigated by the fact that anytime after one year of leaving they can return to standard service as long as costs to other customers are not increased. If costs are increased, the standard service supplier may supply electricity on a basis other than standard service.

No customer has left standard service to date. One customer has joined the market as a result of a legislated requirement. At the time of the market opening, Perth-Andover was a part of the Northern Maine Market, but as of January 1, 2005, became part of the New Brunswick market, and WPS Canada Generation Inc. registered the Perth-Andover load.

While no load physically located outside New Brunswick has elected to join the New Brunswick market, the potential exists for loads, particularly in Northern Maine and Prince Edward Island, to do so. The physical bilateral market design supports the most likely approach which is to maintain the existing load serving entities in each of those jurisdictions, and allow them to purchase energy in the regional marketplace for their scheduled loads under the same contractual arrangements that they use today.

## **2.6 Redispatch Market**

Loads in the New Brunswick market are required to submit balanced withdrawal and injection schedules 24 hours in advance to the NBSO. These schedules essentially

reflect the Bilateral Market where buyers and sellers have entered into contractual relationships. Generators that are committed to the Bilateral Market must submit pricing and quantity dispatch information to the NBSO. There is also an option for generators that are not committed to the market to submit price and quantity information to the NBSO. Based on all of the price and quantity information, the NBSO determines the lowest cost generation mix to meet the load for every hour and issues dispatch instructions. This is carried out independently of the balanced schedule. The difference between the balanced schedule and the dispatch instructions to generators represents the Redispatch Market. Reasons for such differences include:

- Load forecast errors implicit in the balanced schedules;
- Balanced schedules that are not optimized;
- Differences between scheduled losses and actual losses;
- Transmission constraints; and
- Inadvertant energy on interfaces with other systems.

The Redispatch Market can improve the overall efficiency of the electricity market as it is based on least cost. It also provides an opportunity for generation production not tied to the bilateral market to sell into the New Brunswick market.

When the market first opened, NB Power Genco was the only Market Participant submitting price and quantity dispatch data. To address a lack of market participants the NBSO made market rule and tariff revisions to remove entry barriers.

As of March 31, 2008, there were 35 facilities registered in the New Brunswick Market, six were non NB Power affiliated and seven were external dispatchable facilities<sup>7</sup>. Over the reporting period four facilities were added, three of which were external dispatch facilities. Figure 4 illustrates the market progression since its opening in October 2004.

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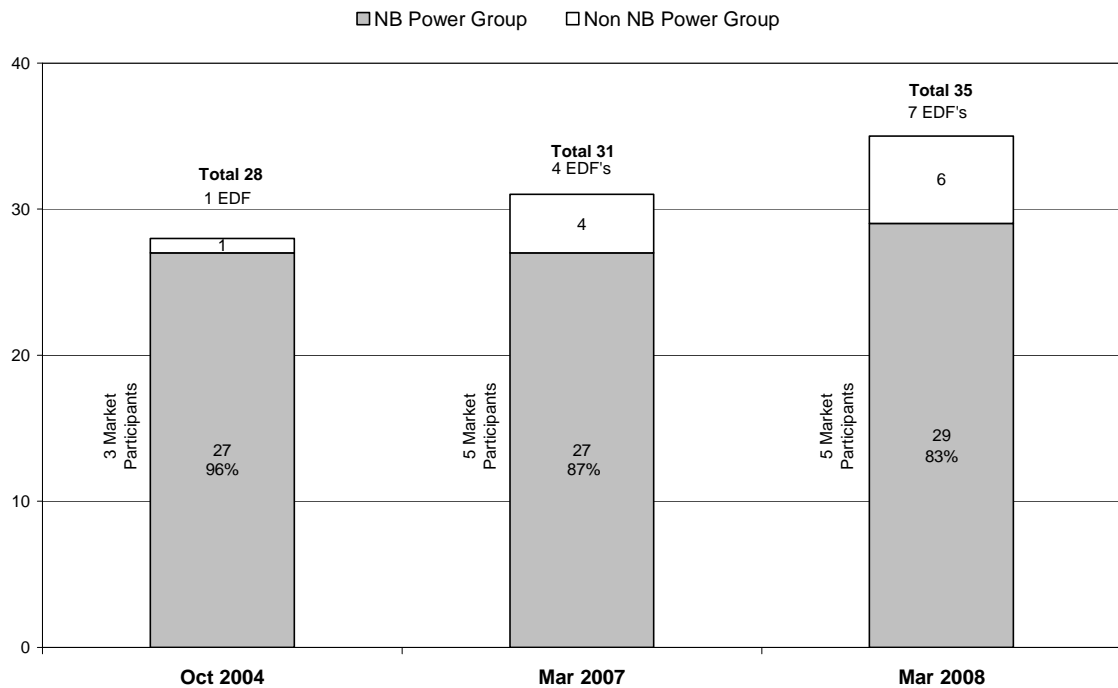
<sup>7</sup> An external dispatch facility is a generation facility or group of facilities located outside of New Brunswick that is registered with NBSO and can be dispatched by NBSO.

Based on ongoing discussions with market participants the trend shown in Figure 4 is expected to continue next year.

While dispatch volumes were not high for external dispatch facilities, the increased activity provides education and experience for the market participants and NBSO. The continued introduction of additional market participants in the redispatch market and increased volume of bidding and dispatch of multiple players will keep competitive pressures on bidding, thereby reducing the dependency on market monitoring. It will also reduce the burden on NB Power Genco as the sole supplier of balancing energy.

**Figure 4**

**Registered Facilities**



Establishment of a liquid market in this redispatch product is important to the continuation of non-punitive pricing for balancing energy, which will become more important and contentious, with the higher volumes of energy imbalance anticipated due to wind power production forecast error.

## 2.7 New Brunswick Final Hourly Marginal Cost

The Final Hourly Marginal Cost (“FHMC”) represents the cost to provide the last MWh of energy on the New Brunswick system. Essentially it is the marginal price of balancing electrical energy in the New Brunswick market.

Figure 5 contains two charts; the top chart illustrates the FHMC for balancing energy in New Brunswick and the bottom chart shows the ISO New England real-time prices at the New Brunswick pricing node. The graphs show both the hourly prices and the moving average weekly price. Both prices are for the same commodity, in the same location, time and currency, but, in different markets. As a result it is useful to compare the prices to gain insight on their relationship.

It is clear from the two graphs that there is not perfect correlation, but, there is some correlation between the two sets of prices. For example during the four months of 2008 the average weekly prices have very similar shapes. This would indicate that the New England price is having an effect on the New Brunswick marginal price. This is expected as the New England prices which are driven by natural gas pricing would compete well with New Brunswick’s petroleum based prices which move into the margin during colder months. In other words the marginal costs in New Brunswick may be governed by New England imports.

Overall the New England price shows a slightly lower level of variability as compared to the FHMC price. The average weekly price in New England rarely falls below \$50/MWh whereas the FHMC weekly average remains below \$50/MWh for a significant portion of the year. This is indicative of New Brunswick’s base load generation facilities that have low production costs and are on the margin during low load periods. There are several time periods in which the FHMC remains essentially fixed, while the ISO-NE price experiences several peaks and valleys.

**Figure 5**  
**Hourly Prices in New Brunswick and New England**

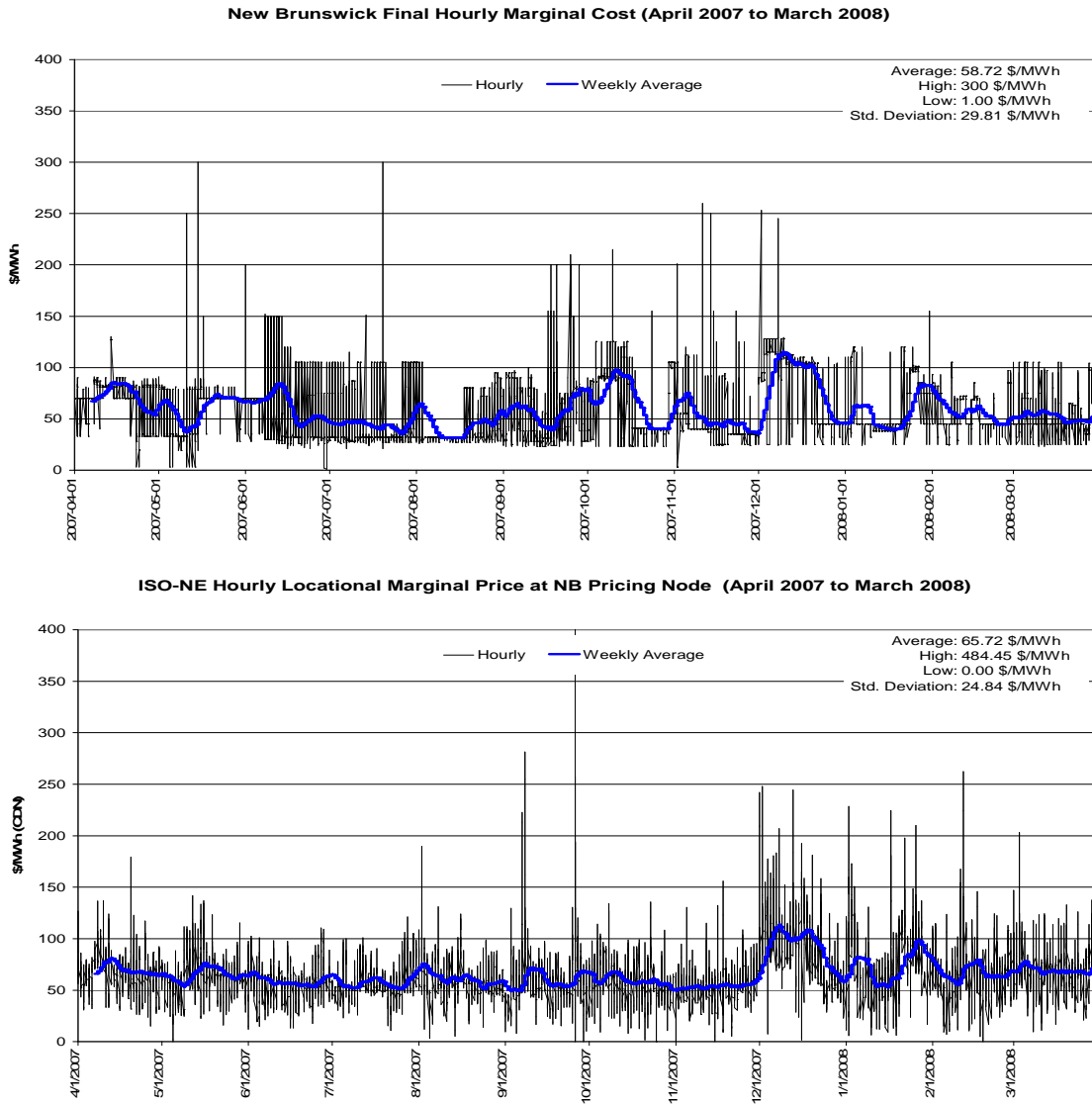
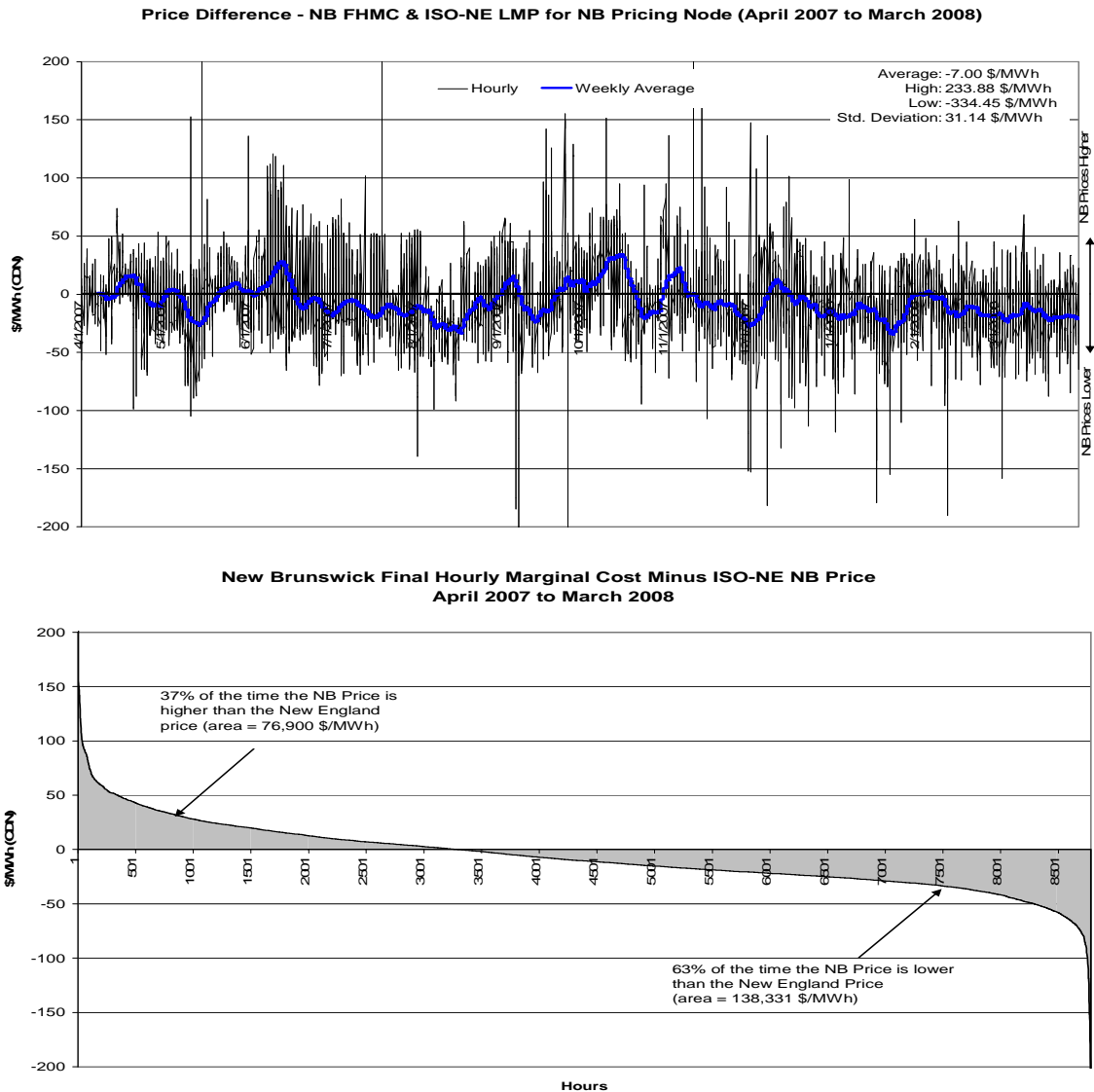


Figure 6 illustrates the difference between the New Brunswick and New England prices both in real time and as a duration curve.

Positive values represent times when the FHMC is higher than the New England price. On average the New England price is 7 \$/MWh higher. During the reporting period the FHMC was higher than the New England price 37% of the time. These are hours where it would make economic sense to dispatch New England facilities to serve New

Brunswick load. During this period the average price difference was 23 \$/MWh with a maximum difference of 234 \$/MWh. The efficiency gains of dispatching a single MW from New England to New Brunswick is represented by the positive area under the duration curve which is \$76,900/MWh. For example, if 50 MW were dispatched during this time period the savings for the New Brunswick system would be \$3.8 million. As more external dispatchable facilities from New England become active in the New Brunswick market the magnitude of this price difference should lower.

**Figure 6**  
**Difference between New Brunswick and New England Hourly Marginal Prices**



Conversely the negative area under the duration curve in Figure 5 represents the possible efficiency gains in New England by dispatching New Brunswick facilities.

As the mechanisms between the two markets become more efficient it could be expected the price differential will decrease and the market prices will move closer together. While the two prices are essentially for the same product at the same location, it is important to note that tariff charges, transmission limitations, and reliability related issues affect the flows between jurisdictions and as a result the price difference will never be zero in all hours.

The NBSO is working with Maine to explore mutual benefits of our transmission systems under the Memorandum of Understanding between Maine and New Brunswick to access the opportunities for better coordination. Under the umbrella of the New England Governors and Eastern Canadian Premiers the NBSO is also working with other system operators in the region to explore the challenges of integrating more wind.

The NBSO remains optimistic that with further education of market participants, the in-service of the IPL/NRI<sup>8</sup> providing easier market access, and the additional participants in the balancing energy market, the FHMC will come to more closely reflect the ISO New England New Brunswick node price, which is presumably indicative of the real-time value of energy in the regional market.

Table 3 compares the New Brunswick Final Hour Marginal Cost for fiscal year 06/07 and 07/08.

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<sup>8</sup> The IPL/NRI (International Power Line/Northeast Reliability Interconnect) is a second 345kV transmission line between the NBSO-controlled grid and the grid controlled by ISO-New England was energized on December 5, 2007.

**Table 3**  
**New Brunswick Final Hourly Marginal Cost**

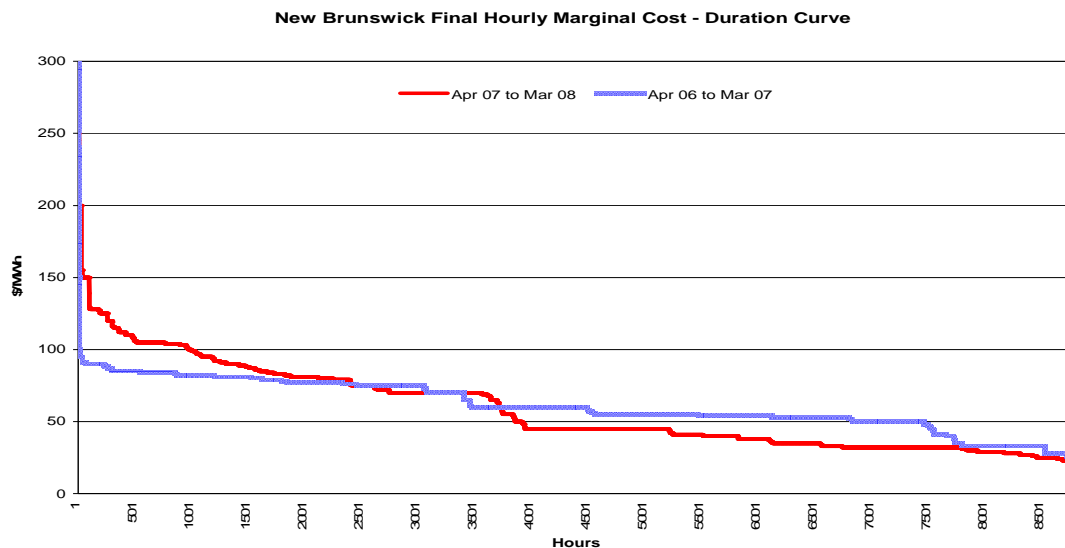
Final Hour Marginal Cost	Apr 06 to Mar 07 (\$/MWh)	Apr 07 to Mar 08 (\$/MWh)
Annual Average	61.62	58.72
Standard Deviation	18.32	29.81
Low	2.00	1.00
High	501	300

Of interest is the fact that the annual average FHMC for 2007/08 was lower than the previous fiscal period of 2006/07. Given that New Brunswick is highly dependant on fossil fuel and considering how fossil prices have increased it would have been expected that the average FHMC would have been higher this year. For the most part the average price in 2007/08 was higher; however, sustained high prices in 2006/07 at the end of the year drove up the average price while lower prices in 07/08 at the end of the year drove the average down.

The variability in the FHMC for 07/08, was much higher than last year. The 07/08 standard deviation of 29.81 \$/MWh was 11.5 \$/MWh than the 06/07 value. While the high and low prices are quite dramatic they only occur for a very short period of time and the high prices are normally driven by special circumstances that require the dispatch of expensive generation for a very short period of time.

Figure 7 shows the FHMC duration curve for 2006/07 and 2007/08. A closer look reveals a significant difference at the high end of the price. In 2006/07 there were only 12 hours where the price was over \$100/MWh and in 2007/08 there were 970 hours with a price over \$100/MWh. The increase in the number of hours with high prices should improve the economics for load facilities who wish to pursue demand response initiatives where load is reduced as an alternative to generation dispatch.

**Figure 7  
FHMC Duration Curve**



## 2.8 Ancillary Services

### Scheduling, System Control and Dispatch

This service is required to schedule the movement of power through, out of, into and within the Control Area in a reliable manner.

The cost of this function for 2007/08 was \$7.751 million (un-audited). This represents a \$0.511 million increase over last fiscal year. The increase is largely the result of increased labour and benefits cost through cost of living allowance increases.

### Reactive Supply and Voltage Control

Reactive supply and voltage control services are mandatory services provided by generators or loads and are required to maintain transmission voltage. The annual expense for 07/08 for this service was \$5.534 million.

Both of the above services are mandatory and are provided by the NBSO on a cost recovery basis through Schedule 1 of the Tariff. It is effectively a monopoly function that enables the operation of a reliable system and market.

While the combined cost of these services is in excess of \$10 million they are not considered to be a barrier to market entry. These services represent a small portion of the total cost of power and are competitive with similar costs in other jurisdictions. For example, the cost is nearly half of the cost in Nova Scotia, British Columbia, and Saskatchewan.

### **Capacity Based Ancillary Services**

Capacity Based Ancillary Services (CBAS) are services that are supplied by generators or loads using capacity with differing degrees of flexibility. There are five distinct services which are listed below from most to least flexible:

1. Regulation - Automated Generation Control (AGC);
2. Load Following;
3. Synchronized/Spinning Reserve;
4. Supplemental Reserve – 10 minutes; and
5. Supplemental Reserve – 30 minutes

These services are provided to ensure system reliability by being able to withstand normal and unexpected changes in either load demand or generation output. They are also vital to meeting the requirements of the North American Electric Reliability Council and the Northeast Power Coordinating Council.

The market in New Brunswick provides loads with the option of self supplying up to 90% of their CBAS requirements. The NBSO is mandated to provide the services at the Tariff rate for the non self supplied portions. The NBSO also has a mandate to provide these services at the lowest possible cost and to facilitate the operation of a competitive

market for the services. In meeting these two objectives it is important to recognize that they can be conflicting, as higher costs may be incurred to initiate a competitive market. Once the market is functioning well the costs should be reduced.

While attempts have been made to develop a competitive CBAS market it has not happened. In the summer of 2006 a Request for Proposals (RFP) was issued for CBAS . Unfortunately, no new participants emerged as NB Power Genco submitted the only valid bid. In July of 2007 an expression of interest was issued to determine whether there was enough interest to justify a second RFP. Interest from loads led to bilateral discussions but with no participation success.

In order to generate interest, greater education of potential bidders is required, as well as discussions as to what, if anything, should be revised in the procurement process, contract, or market rules. During the reporting period the NBSO sponsored a technical session on CBAS issues and will continue with these sessions leading up to either a change in the Tariff and/or Market Rules. Some of the major issues surrounding CBAS are discussed below.

Currently the NBSO only pays for CBAS if they are actually selected for the upcoming hour. This does not place any value on the fact that the supplier of CBAS has committed to having the service available one month ahead should it be needed by the NBSO in the hour-ahead dispatch. The NBSO has proposed that the payments be made by placing 90% of the value to monthly procurement and 10% to hourly procurement.

The NBSO has also proposed that the EUB allow the NBSO (subject to Market Advisory Committee review) to vary the cap on a load's ability to self supply CBAS ranging from 85% to 100%. This would allow the NBSO to better respond to market conditions for competition and to also lower the overall cost of CBAS.

It is worth noting that the cost of providing CBAS has been reduced as a result of the NBSO's reserve sharing agreement with Nova Scotia Power Inc. and participating

NPCC balancing areas. For the next fiscal year the 18-month Point Lepreau Generating Station refurbishment shutdown, which started in April 2008 will decrease the volume of CBAS required as the Lepreau station is the largest generating unit in the balancing area.

## 2.9 Tariff and Market Rule Changes

Market Rule, Tariff and business practice enhancements are an ongoing obligation of NBSO. Enhancements can be driven by things such as problems with existing policies, rules and procedures, external changes to market forces, technology improvements, or new technical standards.

Table 4 contains the key changes that occurred over the period from April 1, 2007 to March 31, 2008. The first change occurred in the previous fiscal year but was not included in last year’s State of Market Report

**Table 4  
Key Changes in Tariff and Market Rules**

Change	Date
Dispatch data change lead time revised from 2 hours to 1 hour. This change allows Market Participants to better respond to changing market and operational conditions.	January 19, 2007
Composition of the Market Advisory Committee expanded to include one representative from the Alternative Generation Class and one from the NB Energy Efficiency and Conservation Agency	October 12, 2007

For the next fiscal period the NBSO will be filing an application with the EUB for changes in the Open Access Transmission Tariff (the “Tariff”). In general the purpose of the application is to propose changes that result in a better alignment of ancillary service revenues with costs. No changes to transmission rates are being contemplated.

## **3.0 General Market Monitoring Activities**

### **3.1 Scheduling Services**

The NBSO continues to offer an optimized scheduling service for market participants using in-house developed software. As the scheduling function would normally be performed by market participants the software only uses information that would be available to the market participant. This avoids any conflict with the non-discriminatory provision of Tariff services.

The service is used by NB Power Genco (as the Designated Scheduling Agent for NB Power Disco) and is available to other Market Participants. The profit from providing this service benefits all Market Participant by reducing the revenue requirement for Schedule 1 (Scheduling, System Control, and Dispatch). The NBSO is able to make a profit due to the fact that the software is very similar to dispatch optimization software used to carry out the NBSO's normal dispatch function.

### **3.2 Residual Uplift**

Residual Uplift is the distribution of the net funds of the Residual Monthly Cost (RMC) after the market settlement with all transmission customers. There are two main factors that contribute to Residual Monthly Cost:

- Re-dispatch – The optimized re-dispatch function undertaken by the NBSO after the balanced schedules are submitted will by design only result in savings in the RMC account. The savings are equal to the price difference between the generator dispatched down, as compared to the generator dispatched up, multiplied by the amount of energy that is re-dispatched.

- Variance/Imbalance – The market settlement as a result of variances in load and or generation can produce negative or positive RMC values.

Socialization of redispatch costs/savings remains a topic of discussion. Some parties have suggested that only those Market Participants that are directly involved in the dispatch portion of the market should receive a share of the redispatch savings. It is important to note that the RMC can also include components other than redispatch cost/savings. In addition, the potential for the total RMC - and thus the Residual Uplift - to be either positive or negative, adds to the complexity of the discussion. Also, there is no one clear measure of the level of participation in redispatch. Consideration has been given to socializing the RMC to (i), in-province load only (ii) Network Customers only, or (iii) all load in the Balancing Area. None of these suggestions stands out as a clear-cut improvement over the current market rule which socializes the costs to all transmission customers in proportion to their respective transmission usage.

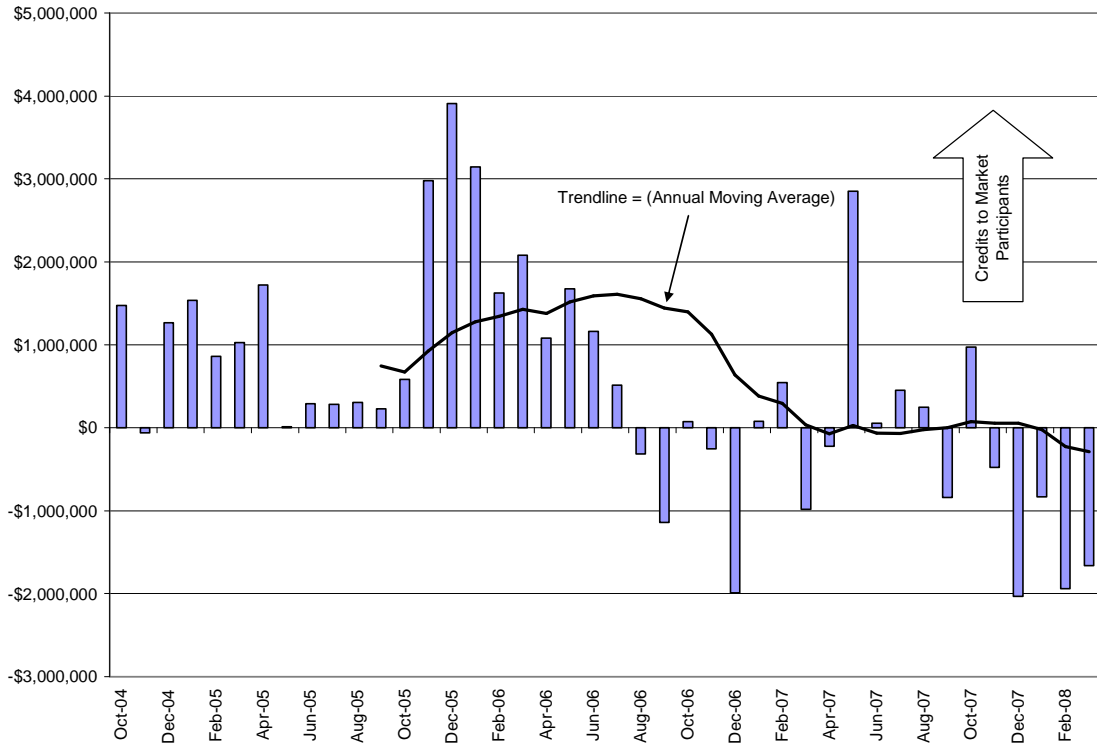
The monthly values of the Residual Monthly Cost are shown in Figure 7. The annual moving average RMC is also shown. It is interesting to note that the annual average for the period of April 2007 to March 2008 is close to zero.

Beginning in November of 2007 the RMC has maintained a negative value. One possible cause may be a bias in load forecasting.

It is important to recognize that the magnitude of the RMC can be influenced by the timing of manual meter readings by NB Power Disco. The timing of when the meters are read can lead to an exaggeration or understatement of the energy consumed in that month, and thus to reduced or increased energy imbalances. A false high energy imbalance leads to a charge to the load-serving-entity for the energy which only appears to have been consumed. There is not an offsetting payment to a generator, because generation is dispatched based on the actual load. Therefore there is an

increase in the dollars in the RMC. The opposite is true when there is a false low energy imbalance.

**Figure 7  
Residual Monthly Cost**



Fortunately this effect cancels out over time as there is not an ongoing bias in the timing of the meter reads. Early reads in one month are followed up by late reads in some later months, thus self-correcting the cumulative impact. With the imbalances settled at FHMC, and relatively stable average FHMC values, the extra dollars distributed in one month tend to be recouped in subsequent months.

While the end result may be the same, the NBSO plans to revise its process to try to reduce the error introduced by the timing of meter reads by estimating the impact and making an adjustment.

### **3.3 NBSO Staffing**

The majority of NBSO staff are seconded employees of NB Power. This arrangement is the result of the natural market transition phase as the NBSO's reliability and operational function was traditionally provided by NB Power. While the staff at the NBSO has signed a Code of Conduct agreement, non NB Power Market Participants may perceive a conflict. While no complaints have been lodged, NBSO is aware that resolving this issue could only enhance the perception of New Brunswick as a jurisdiction with a proactive approach to fair and open access to its transmission system. The Province has publicly stated that it will be reviewing the structure of NB Power and NBSO is hopeful that the review process will lead to a conclusion of the NBSO staffing issue.

### **3.4 Market Participant Behaviors**

During the reporting period there were no reported or verified violations in the Standard of Conduct nor were there any inappropriate behavior or complaints filed with the NBSO relative to Market Participant behavior.

### **3.5 Metering**

Accurate metering is fundamental to the settlement of all energy flows and ancillary services. Market Participants must have confidence in the metering data and its integrity.

The NBSO has identified metering issues in the past and further issues within the reporting period. These errors have been corrected and NBSO has added more data verification to improve the accuracy of metering information and settlement.

## 4.0 Ongoing and Future Market Development

With sustained high fossil fuel prices, greenhouse gas regulations, renewable energy demands, New England electricity load growth, and the Energy Hub concept, the activity in the market is expected to undergo significant changes in the future. In its mandated function to develop an efficient and competitive market, the NBSO will need to continue to make improvements to the market system that encourage a more sustainable future.

It is worth noting that the Minister of Energy has publicly stated that the structure of NB Power and the market is under review. Given the province's desire to develop an Energy Hub that has a strong reliance on private sector investment, there are expectations that the outcome of the review will:

- Ensure non discriminatory access to the transmission system;
- Retain an independent system operator to ensure market fairness;
- Not send a message either perceived or real that would deter private sector investment;
- Support private sector investment in the development of generation for export loads;
- Address the issue of public sector investment to serve domestic load and export opportunity;
- Retain a competitive wholesale market; and
- Provide a level playing field.

The NBSO will work with the Department of Energy as a stakeholder in the development of a new Energy Policy and any reviews of the electricity market design and structure

With the increased interest in wind energy development, the NBSO will be focusing on the challenges of integrating high penetration levels of wind and how market changes can be facilitative.

The need for further work has been identified throughout this report and NBSO has committed to undertake that work. The following is a summary of the key initiatives.

- Continue to pursue efficiencies in dispatch, market administration, and operations.
- Seek details on the standard service rates, terms, and conditions that would apply in the case of a customer serving all or a part of its load from an alternative supply (e.g. exit fees, partial service policies).
- Enhance automated market assessment and monitoring tools.
- Increase system flexibility and competitiveness of balancing energy supply by increasing levels of participation in the balancing energy market.
- Pursue additional supplies of capacity-based ancillary services and competitive pricing of those services.
- Simplify and fine tune the market rules where appropriate (especially with respect to wind power integration).
- Actively monitor transmission planning studies in adjacent jurisdictions and their potential impacts on the New Brunswick market.
- Pursue regional cooperation on issues such as transmission planning, reducing inter-market barriers, and easing wind power integration.
- In keeping with the intent of some aspects of FERC 890 the NBSO will consider the expansion of the regional transmission planning function beyond reliability and ten year time frames to include overall system needs inclusive of economics.
- Review of the overall approach to transmission investment, usage and tariffs given the magnitude of the potential generation, the non-dispatchable nature of proposed generation, and the requirements for significant transmission investments.

## **Appendix 1: Specific Market Investigations and Outcomes**

During the period of April 1, 2007 to March 31, 2008 one complaint was referred to the provincial Regulator. No arbitrations were initiated, and several issues were resolved between the parties involved and NBSO at either the staff or executive levels.

*Ad hoc* investigations into metering and metering processes took place within the fiscal year. Process controls are also in place to reduce the likelihood of a new error being introduced. Ongoing monitoring of “unaccounted for energy” provides a degree of assurance against large metering and metering process errors. Nonetheless, the identification of relatively small meter totalization errors suggests a need to further review existing metering and meter totalization.

Although no specific intervention took place in 2007/08 on FHMC, NBSO remains wary of the limited convergence of FHMC and ISO New England prices. Removing barriers to new bidders (including load) and monitoring bidding strategies of incumbent bidders will continue.

### **Integrys Complaint**

Late in the fiscal year Integrys Energy Services Inc. filed a letter with the EUB opposing NBSO’s proposed change to a Market Rule. The proposed market rule would have changed the procurement of CBAS from hourly to monthly as an interim solution pending the addition of new competitors for the supply of these services. The change was proposed with input from the Market Advisory Committee for the purpose of reducing the likelihood of an NBSO surplus or deficit with respect to these services. The NBSO Board of Directors referred the rule change back to the NBSO staff and Market Advisory Committee for further consideration. The proposed shift to procurement entirely on the monthly basis was revised to 90% of the purchase dollars based on the monthly procurement and 10% based on the hourly. That 90/10 proposal is a component of a more comprehensive proposal for the reduction of the likelihood of an NBSO surplus or deficit on CBAS.

## **MEPCO Roll-in**

The commissioning of the International Power Line Project (the “IPL”) in December of 2007 resulted in transfer capabilities increasing from 700 MW to 1,000 MW for flows from New Brunswick to New England and from 100 MW to 550 MW for flows from New England to New Brunswick. An issue before FERC relative to the treatment of reservation holders on the original transmission line connecting New Brunswick and New England has however restricted transfer capabilities on the New England side of the interface to the lower levels noted above for commercial purposes only. Fortunately, the higher levels of transfer capability would apply with respect to reliability, such as in the case of emergency energy. When the issue is resolved the total transfer capabilities will be 1,000 MW and 550 MW to and from New England respectively, and the firm transfer capabilities for commercial purposes will be 1,000 MW and 200<sup>9</sup> MW to and from New England respectively. The project also provides the benefit of reduced transmission line losses by virtue of being in service.

NBSO continues to actively pursue a resolution to this administrative inefficiency and is adamant that a resolution needs to be put in place prior to the upcoming New Brunswick peak winter period. With the Point Lepreau generating station undergoing an 18-month refurbishment that started in April 2008, the opportunity for commercial imports from outside New Brunswick is extremely important.

## **Schedule Checkouts**

While new tools have been added by system operators in the region to better manage transactions, there continue to be disputes over scheduled transactions between markets. A series of checkouts occur in different timeframes (day-ahead, within-the-day, and after-the-fact) using market-specific energy scheduling systems, a Facilitated Transactions Checkout (FTC) system, and E-Tagging. For a given common interface between two system operator’s

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<sup>9</sup> The 200 MW of firm transfer capability for imports from New England is equal to the transmission capability of 550 MW less 250 MW for transmission reliability margin, less 100 MW for shared activation of reserve.

markets, FTC allows the respective operators to see each other's transactions along with their own. That tool even automatically compares corresponding schedules and highlights where differences exist. E-Tagging is a shared information system that is intended to ensure that a common understanding of scheduled flows is available to all affected system operators and Market Participants. NBSO expects that with this suite of tools available, mismatched schedules will become an extremely rare occurrence.

### **Intra-Hour Sanctions on Nova Scotia Interface**

On February 1, 2008, NBSO implemented an automatic sanction against intra-hour deviations from desired flows on the interface with Nova Scotia. A charge is now applied whenever the average Area Control Error on that interface over 10 minutes exceeds Nova Scotia's *pro rata* share of ISO New England's tolerance for Area Control Error from the Maritimes Area. The purpose of the sanction is to reduce the Nova Scotia Power System Operator's imposition of a regulation burden onto the New Brunswick market. Establishing such protection at this time was influenced at least in part by the understanding that Nova Scotia will be adding at least 500 MW of wind power to its system in the coming years and will therefore have an increased regulation burden on its own system. NBSO has invited the Nova Scotia Power System Operator to work with NBSO to establish a means by which balancing services such as regulation could be transacted commercially between the NB/NME/PEI Balancing Area and the Nova Scotia Balancing Area. Alternatively, the two Balancing Areas could be merged into one, subject to the design of appropriate governance, tariff and market rules. NBSO is optimistic that one of these two initiatives will allow Nova Scotia to achieve its goals for renewable energy on a more cost effective basis, while also protecting the commercial interests of providers of balancing services in the New Brunswick market.

### **Negative Residual Monthly Cost**

The overall history of the RMC is that there have been many months where the RMC resulted in a credit to Transmission Customers, and many where it resulted in a charge to Transmission Customers. In the last 5 months of 2007/08 the RMC was negative in all five

months. NBSO is monitoring this trend and investigating the cause. One possible cause is a bias in load forecasting.

## **Curtailments**

While no transportation system can be expected to be available 100% of the time, it is important that curtailments of transactions be minimized. Market Participants have expressed concern over the frequency and magnitude of curtailments, particularly over the interface with ISO New England. For the majority of the year, work attributable to the integration and maintenance of the IPL was a cause of most curtailments. More recent curtailments have been attributed to specific short-term maintenance work. NBSO continues to monitor these curtailments, the majority of which are initiated by ISO New England.

## Appendix 2: Contestable Customers and Standard Service

As discussed earlier in this report, New Brunswick has yet to see a contestable customer leave regulated standard service rates in favour of market rates. Low regulated rates along with the unknown exit fees have contributed to this lack of movement. There are growing signs that these conditions may not prevail in the future. It can be expected that regulated rates will continue to rise given their strong link to fossil based heritage assets. The recent changes in the Act allowing for a hearing on exit fee methodology will also help reduce the unknowns.

In support of a competitive market, the NBSO will monitor and report on the conditions that would promote greater activity. The objective is to provide contestable customers with enough information to allow them to decide whether or not the option should be explored further.

In order for it to be economic to leave standard service, two fundamental conditions need to exist. Market rates must be lower than the regulated (standard service) rates and the exit fee must be less than the difference between the regulated and market rates.

$$\text{Load Benefit} = \text{Regulated Rate} - \text{Market Rate} - \text{Exit Fee.}$$

The purpose behind an exit fee is to ensure that the remaining standard service customers remain whole. When load leaves standard service, NB Power Disco (the standard service supplier) loses the revenue associated with the electricity sale, but, at the same time they avoid the cost associated with buying the electricity. To ensure that the remaining ratepayers are no worse off, an exit fee would be applied to the load if the revenue loss is higher than the avoided cost which could be expressed as follows.

$$\text{Exit Fee} = \text{Regulated Rate} - \text{Avoided Rate}$$

It is assumed that there would only be an exit fee and not an exit benefit. If NB Power Disco made gains as a result of a load loss, those gains would not be transferred to the load that left. While not discussed herein, there is a situation where both the exiting load and remaining standard service customers would be better off if a mechanism to share the NB Power Disco benefits existed. It is important to keep in mind that the methodology to be used for the determination of exit fees has yet to be tested with the Energy and Utilities Board.

If the two formulas noted above are combined, the benefit formula is simplified as follows.

$$\text{Load Benefit} = \text{Avoided Rate} - \text{Market Rate}$$

This formula only works when the market rates are lower than regulated rates and where the exit fee is positive. If the exit fee is negative the Load Benefit is reduced by the amount of the exit benefit to NB Power Disco.

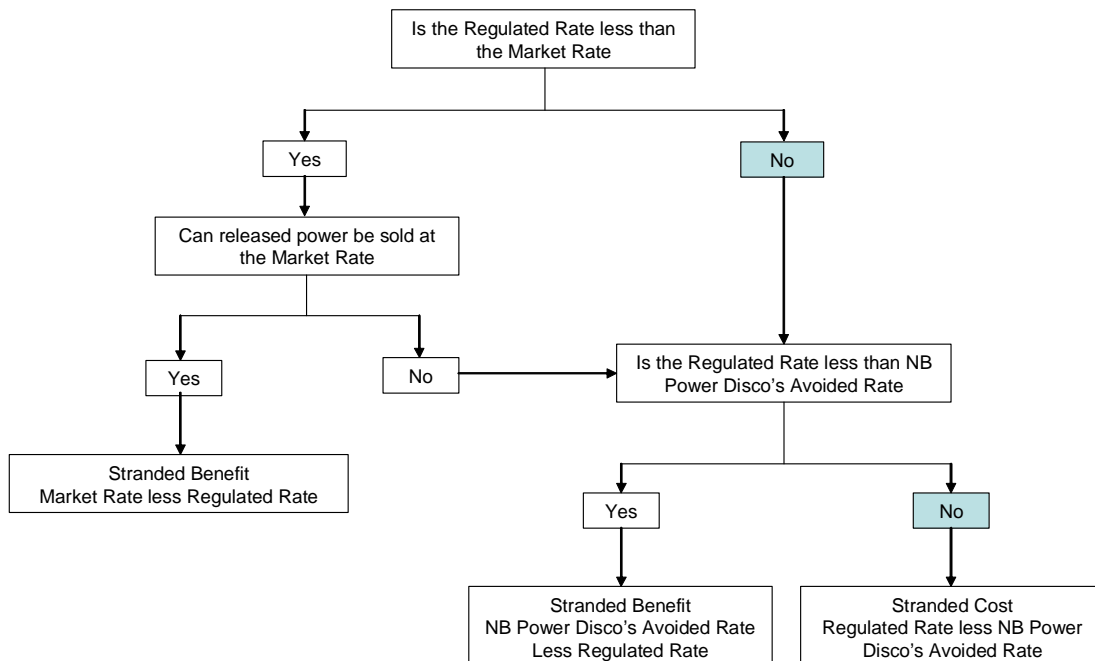
The formula illustrates that the avoided rate is critical to the analysis. The avoided rate will vary with the amount of load that is leaving and is a complex analysis that can only be undertaken by NB Power Disco. However, as a proxy, the FHMC which represents the cost of providing the last MWh on the New Brunswick transmission system could be used. For fiscal year 07/08 the average FHMC was 58.72 \$/MWh. As the FHMC is determined at the generator it needs to be adjusted to account for transmission losses. Assuming losses of 2.5% the adjusted avoided rate is  $58.72 / (1 - 0.025) = \$60.23$ .

This snapshot analysis suggests a market rate of less than \$60.23 would result in a breakeven for a contestable customer to leave. It is conceivable that in certain circumstances the market could supply at this price. For example, a cogeneration facility that has two products for sale, heat and power, could sell electricity at a price of 60.23 \$/MWh. Estimates for the cost of new nuclear facilities are also in the \$60 to \$70/MWh range.

Given the critical importance that avoided cost has in the analysis, it is strongly suggested that the standard service supplier publish their avoided cost. This would provide contestable customers with the information required to make an informed decision on leaving the system.

It is understood that a load's decision to leave standard service is not simple. There are many other factors that need to be considered such as a forecast of regulated rates, market rates, the standard service supplier's avoided cost and an assessment of risk. Some risk is mitigated by the fact that load can return to standard service one year after leaving as long as costs to other customers are not increased. If costs are increased, the standard service supplier may supply electricity on a basis other than standard service.

The following chart is taken from the Market Design Committee Report and is useful in understanding the conditions that can lead to an exit fee or benefit. The highlighted boxes indicate the conditions described above.



## **Appendix 3: Glossary of Terms**

### **Ancillary Services**

Those services necessary to support the transmission of capacity and energy from suppliers to consumers while maintaining reliable operation of the transmission system.

### **Dispatch**

The production requested of a facility by the system operator.

### **Energy Imbalance**

The difference between the expected hourly production (or consumption) and the actual production (or consumption). In the case of generators the expected production is the amount dispatched by the system operator. In the case of loads the expected consumption is the amount scheduled by the respective market participant.

### **Final Hourly Marginal Cost (FHMC)**

The reduction in production costs that would be realized by a 1 MW reduction in the dispatch requirements for a given hour, as calculated just prior to the start of that hour.

### **Open Access Transmission**

Non-discriminatory access to the electric power transmission system for generators and consumers.

### **Redispatch**

The difference between the hourly production indicated by market participant schedules and the production requested by the system operator.

### **Residual Monthly Cost (RMC)**

The aggregate of amounts reflecting the costs, debits, and credits related to market operation functions such as redispatch, energy imbalance, penalties to market participants, and emergency energy transactions.

#### Appendix 4: Transmission Purchasers Key

Short Name	Full Name
NBDC	NB Power Distribution & Customer Service Corporation
NBPM	NB Power Generation Corporation
NBNU	NB Power Nuclear Corporation
MEHQ	Hydro-Québec Energy Marketing Inc.
MECL	Maritime Electric Company Limited
NMISA	Northern Maine Independent System Administrator
NSPI	Nova Scotia Power Inc.
AVEC	Boralex Fort Fairfield Inc.
EMAE	Emera Energy Inc.
EMI	Brookfield Energy Marketing Inc.
WPCG	WPS Canada Generation Inc.
WPSE	WPS Energy Services Inc (now known as Integrys Energy Services Inc).
TransEn	TransÉnergie (a business unit within Hydro- Québec)
ISO-NE	ISO New England