New Brunswick Market Design Committee
Final Report

April 2002

New Brunswick Market Design Committee Website

www.nbmdc-ccmnb.ca

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EXECUTIVE SUMMARY

Introduction

The Final Report of the New Brunswick Market Design Committee presents a design for implementation of electricity re-structuring as adopted by the Government in the *White Paper: New Brunswick Energy Policy*. The Report contains a summary of the analysis and recommendations presented in Interim Reports released by the Committee at the end of each of the three phases of its work.

The Final Report, representing the culmination of ten month's work by the Committee, presents two resolutions and ninety-five recommendations designed to work in concert to help achieve the key policy objectives set out in the *White Paper*.

White Paper Objectives

The Government of New Brunswick appointed the Market Design Committee (MDC or Committee) in June 2001 to advise on the implementation of the electricity restructuring initiatives spelled out in its *White Paper* on energy policy. In its *White Paper* the Government of New Brunswick defined policy goals that set the context for the work of the New Brunswick MDC.

Decisions Taken By Government

A number of key decisions taken by the Government of New Brunswick with respect to electricity market design were described in the *White Paper*. Among the most important for the electricity supply industry were:

- The electricity sector will be restructured;
- Progress towards restructuring will be "deliberate and controlled". This includes the initial introduction of competition only at the wholesale and large industrial retail level;
- Customers that do not elect or are not eligible for a competitive electricity retailer will be entitled to a standard offer service similar to the current service provided by their existing utility;
- The mandate of the Board of Commissioners of Public Utilities (PUB) will be expanded to include regulation of many aspects of the new electricity market structure;
- Green pricing options will be made available and opportunities reviewed for development of small scale, on-site electricity generation;
- Any restructuring of NB Power will be considered separately from the market design process.

The *White Paper* directed that the MDC will "address development of the electricity market including its design, structure and rules, and make recommendations to the province by April 2002."

Recommendations

The Committee is recommending that New Brunswick institute a bilateral contract market in which wholesale and large industrial retail customers could contract with alternate providers for electrical energy needs. In addition, any power generator or supplier would be free to sell by contract to eligible customers inside and outside the Province.

In order for a bilateral contract market to function effectively, there must be open and non-discriminatory access to the transmission system for all eligible buyers and sellers. Having an open access transmission policy also helps to satisfy FERC requirements, essential to putting generators based in New Brunswick in the best position to sell electrical energy in the emerging open markets in New England and elsewhere in the U.S.

Implementing the bilateral contract market would require establishment of a system operator. The MDC agreed that the primary consideration in the implementation of the market is the assurance of total independence of the transmission system and system operations from the owners of generation. The MDC is recommending that the system operator be part of the entity that owns and operates the transmission system, and that the system operator have a governance mechanism ensuring that, with respect to market functions, it would report to an independent board. It is also recommending giving the system operator broad authority and responsibility to operate and administer the market and the electricity supply system.

At the same time as calling for the introduction of a competitive wholesale market for electricity, the *White Paper* directed that customers who do not, or cannot, choose an alternative supplier should be entitled to "standard offer service under regulated prices and terms that are consistent with the service they now obtain."

To supply standard offer service, the MDC is recommending designating a 'Heritage Pool' of electricity available from the existing generation assets in the province. As these assets retire, and as load grows, the standard offer service supplier would go to the market for new supply. The standard offer service supplier would be required to use a request for proposals for acquisition of supply from the market beyond the Heritage Pool amount. The MDC is recommending that, to preserve the option for present and future consumers of not having to go directly to the marketplace to obtain energy, some form of standard offer service should be offered indefinitely.

Contestable customers (those eligible to choose alternative supply) might want to leave from and return to standard offer service supply, and they might want to be able to take only a portion of their total needs from standard offer service supply. As recommended by the MDC, contestable customers could leave and return, but with some restrictions.

Customers leaving from or returning to standard offer service supply would be responsible for any costs their actions impose on other market participants.

The MDC recognized that, in the current context of electricity restructuring, using the term “de-regulation” is a misnomer. The bilateral contract market entails entirely new responsibilities for the regulator in New Brunswick, the PUB. The MDC is recommending that the PUB’s role include oversight of the system operator and responsibility for monitoring for the abuse of market power.

A major goal of the New Brunswick Energy Policy is to protect and enhance the environment. Electricity market restructuring can potentially contribute to achieving environmental policy objectives. Total economic costs of low-impact technologies may be lower than those of conventional technology when environmental damage costs are considered.

The MDC is recommending a number of positive programs to help the government meet its goals with respect to environmental protection and enhancement. These include net metering, support for embedded generation, renewable portfolio standards, energy efficiency programs, green pricing, broad-based CO_2 emissions trading, emission performance standards, and the promotion of cogeneration.

Future Steps Required

The Market Design Committee makes recommendations on the nature and function of the electricity market in New Brunswick. To implement them requires a more detailed set of rules for the operation of the market, and the Committee is recommending a process and principles for the initial development of market rules.

Summary

The challenge given to the Market Design Committee was to design a new framework enabling the Province to move from an electrical energy supply system dominated by a vertically integrated provincial utility to a system that allows for independently owned generation and where wholesale and large industrial retail customers are free to acquire electricity from alternate suppliers.

Central to that challenge was the task of finding a balance between the *White Paper* objectives of creating and encouraging a competitive market for electric power, and maintaining a standard offer service for those customers who are not eligible, or chose not to obtain their electrical supply directly from the marketplace.

In addressing this challenge, the Committee was guided by a number of criteria including reliability, fairness, robustness, environmental protection and enhancement, and protection of non-contestable customers.

The balance struck by the Committee should provide for the continuance of a reliable, cost effective, electrical energy supply, enhanced by the provision of alternate supplies and new generation from the marketplace, to meet future load growth.

1 INTRODUCTION

The Government of New Brunswick appointed a Market Design Committee (MDC or Committee) in June 2001 to advise it on the implementation of the electricity restructuring initiatives spelled out in its *White Paper* on energy policy.[1] The MDC was instructed to produce final recommendations by April 2002 to the Minister of Natural Resources and Energy.

1.1 Policy Objectives

In its *White Paper* the Government of New Brunswick set out energy policy objectives and a number of decisions and directives. The policy goals are:

- To ensure a secure, reliable and cost effective energy supply for residential, commercial and industrial customers;
- To promote economic efficiency in energy systems and services;
- To promote economic development opportunities;
- To protect and enhance the environment; and
- To ensure an effective and transparent regulatory regime.
- These goals set the context for the work of the New Brunswick MDC.

1.2 Decisions Taken By the Government

A number of key decisions were taken by the Government of New Brunswick with respect to electricity market design before the appointment of the Market Design Committee. They are described in the *White Paper*. Specifically, the following decisions were enunciated:

- That the electricity sector will be restructured.
- That progress towards restructuring will be "deliberate and controlled" rather than rushed. This includes the initial introduction of wholesale and large industrial retail competition and the consideration of the merits of mass market retail competition.
    - o Customers that do not elect a competitive electricity retailer will be entitled to a standard offer service similar to the current service provided by their existing utility.

[1] Government of New Brunswick, *White Paper: New Brunswick Energy Policy*, January 2001.

- That New Brunswick Power Corporation (NB Power) will be directed to continue to discuss aligning its transmission with that of its neighbours in a Regional Transmission Organization (RTO) to facilitate cross-system flows.

- That to satisfy the requirements of the Federal Energy Regulatory Commission (FERC) Orders 888 and 889, New Brunswick will have an Open Access Transmission Tariff (OATT).

- That any restructuring of NB Power will be considered separately from the Market Design process, except to the extent that the MDC's considerations of RTO operations or market power mitigation impact the utility.

- That the resolution of financial and operating issues associated with the provincial utility are also outside the MDC's terms of reference, except to the extent that such matters as exit fees or equivalent charges are examined for their impact on competition.

- That the Market Design process will be open, with extensive participation from government, industry and other stakeholders.

- That final recommendations are required by April 2002 and that these must address all of the Committee's terms of reference.

1.3 Terms of Reference in the *White Paper*

The *White Paper* said that the MDC will "address development of the electricity market including its design, structure and rules, and make recommendations to the province by April 2002."

The *White Paper* contained several specific tasks for the MDC. The *White Paper* says that the MDC will be instructed to:

- Make recommendations on all codes and operating protocols;

- Make recommendations on market surveillance and establishing a workably competitive market;

- Consider reliability of supply for New Brunswick in its market design recommendations;

- Examine means to avoid rate shock to existing self generators (for ancillary services, transmission, standard offer backup);
- Make recommendations for mitigation of market power in the wholesale and large retail markets;

- Assess methods of stranded cost recovery;

- Examine and make recommendations on the need for reciprocity in New Brunswick electricity market design; and

- Review and make recommendations on the role and treatment of small-scale, on-site electricity generation.

The MDC understood these instructions to be within the context of the New Brunswick energy policy as set forth in the *White Paper*.

1.4 Contents of This Report

The report is organized around the major topic areas the MDC has identified.

The first chapter addresses the Committee's terms of reference and its process.

The remaining chapters address the topic areas. They are, in order, basic market design including System Operator definition and governance, System Operator responsibilities, reliability, and reciprocity; standard offer service; environment and renewables; market power; regulator roles and responsibilities; transmission; and continuing processes including market rules. All of the MDC recommendations appeared in one of the three Interim Reports.[2] The numbers in square brackets after each recommendation refer to their source. The first number refers to the Interim Report where the recommendation appeared; the second number, after the colon, is the section of that report which contained the recommendation.

In addition, the MDC made resolutions that related to broad policy directions which the Committee felt should be followed.

The report has several appendices. The first appendix lists all recommendations made by the Committee, with cross references to the Interim Report where they first appeared. Appendix B lists the Committee members and their alternates. Appendix C contains a glossary. Appendix D has a list of the MDC's major publications which are available on its website (www.nbmdc-ccmnb.ca).

[2] The wording of some recommendations has been altered slightly to be consistent in style or content with later recommendations of the Committee.

2 MDC MEMBERSHIP AND PROCESS

2.1 Membership of the Committee

In keeping with the commitment in the *White Paper* to an open process, the Minister appointed a multi-stakeholder MDC. The Committee included members affiliated with generators, large industrial customers, municipal utilities, environmental groups, the Premier's Roundtable on Environment and Economy, the regulator (Board of Commissioners of Public Utilities (PUB)), the Department of Natural Resources and Energy (Department), and the Crown utility. A list of Committee members and their alternates is in Appendix B.

The members of the MDC represented both their own organizations and other stakeholders in their constituency group. The MDC members consulted with these stakeholders in order to bring wider participation to the MDC process.

The MDC also established a web site and posted on it many documents presented to the Committee. Interested parties were invited to provide feedback to the Committee through the web site (www.nbmdc-ccmnb.ca).

2.2 MDC Terms of Reference and Process

The MDC debated, revised and adopted a document setting out its task and describing its decision making and internal process. The document is called the Terms of Reference and Process.

This document lays out the essentials of the MDC's tasks. It specifies the deliverables the Committee expects to produce, the issues that the Committee will address, a high-level agenda assigning those issues to the three Phases of the Committee, and an agreed process for the deliberations and administration of the Committee. The deliverables are described in the Terms of Reference document as:

The design of the wholesale electricity market in New Brunswick, including all aspects required to make the market viable and workably competitive.

- The design structure and roles for the electricity market
- Codes and Operating protocols
- Oversight of the electricity market including
  - Market Surveillance
  - Mitigation of market power in the wholesale and large industrial retail market
- Transitional issues from regulated to competitive market
  - Method of stranded cost recovery
  - Exit fees (or equivalent charge) for self-generators
  - Exit fees (or equivalent charge) for large customers
  - Means to avoid rate shock to existing customers

- Issues related to neighbouring jurisdictions
    - o Need for reciprocity in New Brunswick market

These deliverables cover the mandate given to the MDC in the *White Paper*.

The Committee organized its work into three phases, each taking one calendar quarter.

In the first phase, the Committee focused on basic issues of market design. These included the choice of a basic market design and identification of a System Operator, and first considerations of issues relating to transmission and to market power. The second phase dealt with institutional issues. Institutions addressed included the System Operator, the regulator, and the standard offer service and its supplier. During this phase the MDC also began discussion of environmental and market power issues. In its third phase, the Committee focused on transitional issues. Among these were considerations of how to deal with stranded costs, if any, and the process for creating the rules that will be needed to implement the market design. In the third phase, the MDC also concluded its discussions of policies for environmental protection and enhancement and for mitigation of market power.

In its discussions, the MDC considered a number of Issues Papers, each of which introduced an issue, its possible resolutions, and experience in other jurisdictions. All the Issues Papers are posted on the Committee's website.

For each of its three phases, the Committee issued an interim report. All the interim reports are on the website. This Final Report summarizes many of the Committee's discussions, which are reported in more detail in the interim reports.

2.3 Criteria for Decisions

The Committee discussed and adopted criteria for decision making, as described in Issues Paper #1: Criteria for Decisions. The Issues Paper lists objectives of electricity restructuring in general, and a set of criteria for decision making.

The Issues Paper notes that generally the two major goals of electricity market restructuring are to achieve greater economic efficiency in the electricity supply system and to allocate risks to the parties best positioned to control or to absorb the risk.

Criteria for decisions are:

- reliability;
- transparency;
- fairness;
- robustness;
- enforceability;
- environmental protection and enhancement; and

- protection for non-contestable customers.

Issues Paper # 1: Criteria for Decisions elaborates on the dimensions of each of these criteria.

3 MARKET DESIGN

An electrical power system such as the one in New Brunswick consists of generation facilities, a transmission system, distribution systems, and end-use customers. The generation facilities produce power and the end-use customers consume power. The transmission system moves power in bulk from generation facilities to (1) a relatively small number of directly connected industrial end-use customers that have high volumes of consumption, (2) directly connected distribution systems, and (3) transmission systems in neighbouring jurisdictions which are also directly connected to the transmission system. The distribution systems are localized and provide paths for power to flow from the transmission system to the remainder of the end-use customers.

The choice of basic market model was the first major item on the MDC agenda. Having identified the model, the Committee made recommendations on the appropriate components to be included to establish a workably competitive market.

The *White Paper* clearly stated that the New Brunswick electricity market would allow all industrial customers connected to the transmission system with loads 750 kW or more, and all wholesale customers (the municipal utilities) the ability to choose their electricity supplier by April 2003. Any market design the Committee recommended would have to be able to perform that function within that timetable.

The *White Paper* also said that customers who do not (or cannot) choose an alternative electricity supplier will be entitled to purchase electricity under terms and conditions consistent with the service they now obtain. This condition led to the discussion of the standard offer service (SOS).

3.1 Basic Market Model

The Committee considered several candidate models of electricity markets. Issues Paper #2: Choice of Market Model contributed to this discussion.

The existing model is that of a vertically integrated monopoly utility. In the case of New Brunswick, that utility is NB Power, a Crown corporation.[3] This model was not further considered, since it will not allow the degree of competition specified in the *White Paper*.

Three other models were described and discussed:

- A market based on bilateral contracts between generators and wholesale and large industrial retail electricity buyers;

[3] A parallel project of the Department of Natural Resources and Energy is considering the future structure and ownership of NB Power.

- A spot market organized around a bid-based pool administered by an independent market operator (IMO);[4] and

- A single buyer/reseller market.

Each of these markets is discussed in more depth in Issues Paper #2. That paper includes a description of how the market works, its advantages and disadvantages, and examples of markets in other jurisdictions which have used that model.

3.1.1 Bilateral Contract Market

Wholesale market bilateral contracts are agreements between electricity generators and wholesale customers for the delivery of electricity. They can be financial or physical bilateral contracts. A financial contract specifies the amounts and time of the delivery of electricity and the price or price formula for the settlement. The actual generation and delivery take place according to the rules of the market, and the participants to the financial bilateral contract then settle between them any differences between their contract price and the price in the market.

A physical bilateral specifies amounts of injections and withdrawals, the timing of the injections and withdrawals, and the nodes where they take place. These conditions are scheduled with the System Operator. To be an effective contract, a physical bilateral must also include transmission rights between the injection and withdrawal points.

The bilateral contract model allows for the bilateral contracts to be essentially fringe competition to an existing dominant generator. Over time, the bilateral contracts could be expected to increase as a fraction of the total market, creating more competition. Such a bilateral contract market represents one way to implement a gradual approach to introducing competition in electricity supply.

A bilateral contract market does require several other conditions. Most important is that there must be open and non-discriminatory access to the transmission system for all potential buyers and sellers. To fulfill the bilateral contracts, the seller must transmit electricity to the buyer. If the transaction is subject to either arbitrary pricing or arbitrary scheduling by a System Operator who is essentially a competitor of the supplier, the market is not likely to be competitive. Additional conditions for a competitive market to develop include a sufficient number of potential customers and market price sufficiently high to attract new entrants.

The MDC discussed the advantages and disadvantages for New Brunswick of adopting a bilateral contract market as its basic market design.

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[4] In this report, a distinction is made between an IMO which administers the electricity exchange or bid-based pool and an independent System Operator (ISO) which is responsible for the operation of the system.

3.1.2 Fully Competitive Wholesale Pool Market

This model requires the creation of a region-wide competitive wholesale "pool", in which an Independent Market Operator (IMO) administers a regional dispatch based on offers and bids submitted by market participants. This is the form of competition adopted by many jurisdictions that have restructured. The market has many sellers who compete with each other. There typically are multiple wholesale buyers.

Prices in the wholesale pool are based on competitive offers and bids submitted by market participants. The actual dispatch is based on the same offers and bids from buyers and sellers in the market. Prices are derived from the dispatch and the offers and bids, and generally define the price that exactly clears the market. For example, the market-clearing price may be that price at which the price for the last increment of electricity offered to sell is equal to the price of the last increment of electricity offered to buy.

The Committee discussed the advantages and disadvantages for New Brunswick of a competitive wholesale pool market.

3.1.3 A Single Buyer Market

The Single Buyer Model for electricity restructuring is centered on the principle of monopsony, a monopoly buyer facing competitive suppliers. It is a first step towards competition from a vertically integrated monopoly utility structure. This model can be implemented in a number of ways. The generation assets of the formerly vertically integrated utility can be sold to several investors, and long-term power purchase agreements (PPAs) established between the monopoly buyer and the new Gencos. Alternatively, the vertically integrated utility can be maintained and it can acquire power through a competitive bidding process or other market-based processes.

The MDC did not discuss this model at length because it does not give electricity customers any choice and hence, does not achieve the level of market reform dictated by the *White Paper*.

3.1.4 MDC Recommendation on Basic Market Model

The MDC held extensive discussions on the choice of basic market model. Through the discussion, the MDC decided that the most suitable model for the currently envisioned market in New Brunswick is the bilateral contract market model. The bilateral contract market allows eligible buyers and sellers to contract in any way they wish. It directly fulfills the requirements as set forth in the *White Paper* to allow wholesale and large industrial customers to choose their electricity supplier. It is consistent with the current direction of NB Power, which already has an Open Access Transmission Tariff (OATT) and is planning to produce a FERC-compatible tariff.

One Member of the Committee held the view that New Brunswick should move directly to implement a wholesale pool market. This would be seen as being part of a larger pool market, incorporating at a minimum, New England. This option was seen by that member as fostering a more competitive market environment in a shorter period of time.

Recommendation 3-1. The MDC will pursue the development of a bilateral contract market for New Brunswick. [1: 3.2]

3.2 Market Participants

Buyers

The *White Paper* specified that all wholesale customers and all industrial customers with a minimum load of 750 kW, taking supply directly off the transmission network, would be eligible to choose their own electricity supplier

The *White Paper* did not specify any other entities as potential buyers of electricity in the contestable market. In order to encourage the development of a robust market, the MDC wanted to include participants other than end-use buyers, such as agents, brokers, traders, marketers and aggregators

Recommendation 3-2. The MDC recommends that eligible buyers in the New Brunswick bilateral contract market will include wholesale customers and industrial end-use customers with a minimum load of 750 kW, taking supply directly off the transmission network. Participants will also include all agents, brokers, traders, generators, marketers and aggregators licensed in New Brunswick.[1: 3.3.1]

Sellers

The *White Paper* did not comment on who would be eligible to sell in the New Brunswick contestable market.

In some markets, participation is limited to generators of a certain size. Small generators may not be able to afford the infrastructure needed to participate in competitive wholesale pool markets. In a bilateral contract market, however, any generator can contract if it chooses to accept the costs of market participation.

Sellers can also include suppliers from outside New Brunswick. They will have access through the interties and the open access transmission system. Finally, if the agents, brokers, traders, marketers and aggregators are eligible to buy, they must (since they are not end users themselves) also be able to sell.

Recommendation 3-3. The MDC recommends that all eligible generators and all eligible importers may sell in the New Brunswick bilateral contract market.[1: 3.3.1]

The MDC discussed whether generators who are embedded in a distribution system are eligible to sell into the bilateral contract market. They are only connected to the transmission system through their host utility. To be able to participate in the bilateral contract market, they need to be able to contract with buyers. One potential buyer is the host utility itself. Other potential buyers are eligible customers in the bilateral contract market.

From the viewpoint of the system, the only effect of the operation of the electricity market embedded generator is to reduce the load of the host utility. To schedule a physical contract, the embedded generator should schedule with the System Operator. The System Operator will then schedule supply for the host net of the scheduled self-generation.

In light of these considerations, the MDC adopted the following recommendation.

Recommendation 3-4. The MDC recommends that generators embedded in distribution systems be eligible to participate in the bilateral contract market, subject to market rules. They must inform the host utility when they are injecting.[2: 6.2.5]

Implementing this recommendation could give rise to disproportionate administrative costs. The MDC recognized that the host utilities should not have to bear these costs.

3.3 System Operator

The MDC identified two sets of issues with relation to the System Operator: institutional and functional. The institutional issues include its identification, independence, governance, and funding and accountability. The functional issues are the System Operator's roles and responsibilities, including those with respect to the bilateral contract market, the transmission system, ancillary services, forward planning, and the market rules.

3.3.1 System Operator Institutional Issues

The institutional issues discussion began with the consideration of independence. Presentations and other information given to the Committee emphasized the importance of independence of the System Operator from other market participants, especially those owning or controlling generation.

The current situation in New Brunswick is that NB Power is a vertically integrated monopoly utility. It owns and controls generation, transmission, and distribution assets. NB Power has separate business units for each of nuclear generation, conventional generation, transmission, and customer service/distribution. To create complete corporate independence for the System Operator, therefore, requires some change in the corporate or operational structure of NB Power.

The Committee recognized the importance of keeping the System Operator independent of the owner and operator of any generation. The Committee considered three models with increasing degrees of independence:

- Functionally unbundled System Operator, part of a vertically integrated company,

- System Operator as part of corporately unbundled transmission owner and operator,

- Fully independent System Operator.

The MDC is aware that the New Brunswick government has underway a separate project to decide on the corporate structure of NB Power. This project will recommend to the Minister a corporate and ownership structure for NB Power.

To balance between independence of the System Operator and the cost of transition, the MDC decided to adopt a "transitional Transco."[5] The transitional Transco would incorporate the functions of transmission system owner and operator with those of the System Operator. The model can readily transition to a fully independent System Operator at some time in the future, when the development of the New Brunswick electricity market warrants it. To emphasize the importance it placed on independence of the System Operator, the MDC adopted Resolution 1.

Resolution 1. The MDC agrees that the primary consideration in the implementation of the market is the assurance of total independence of transmission system and market operations from generation.

The MDC also adopted Recommendation 3-5, which provides for a transitional Transco.

Recommendation 3-5. The MDC recommends that the System Operator for the New Brunswick bilateral contract market be part of an organization that includes the transmission system owner and operator.

The MDC recommends that this be implemented as a functionally separate Transco business unit under separate "corporatized" accounts from the rest of NB Power (Generation, Distribution and Marketing). To realize the goal of independence of the transmission system and market operations from generation the Market Design Committee recommends that in the long run the Government pursue a Transco-based model or model that provides an equivalent level of independence (ISO).[2: 2.1.1]

Given this recommendation, the next issues were the corporate organization and governance of the Transco and its accountability. The MDC was uncertain of the direction that the government of New Brunswick will take with respect to the ownership and corporate organization of NB Power. In the absence of a clear indication from the Province, the Working Group chose to make recommendations on two different System Operator arrangements:

[5] In current usage, a Transco is an owner and operator of a transmission system and System Operator which is independent of other market participants.

- Independent Transco – which involves combining transmission ownership and System Operator functions in a separate corporate entity to that of the generation owner, and

- Functionally Independent System Operator – which involves establishing an independent governance arrangement for the System Operator function within a single corporate entity that owns both generation and transmission facilities as well as being the System Operator.

The MDC noted that independence from generation and other market interests is important for the transmission owner and System Operator.

For an Independent Transco that is a separate corporation, the MDC recommends an entirely independent Board of Directors.

Recommendation 3-6. The MDC recommends that, if the entity containing the System Operator is a corporation independent of the corporations responsible for generation, the Board of Directors of that corporation consist entirely of members who have no direct connection with or beneficial interest in any participant in the New Brunswick electricity market. [2: 2.1.2]

Alternatively, if the System Operator function remains part of a vertically integrated corporation that owns and operates both generation and transmission assets, the MDC still strongly held the opinion that at least the System Operator functions need to be assured of independence from the conflicting pressures that the generation ownership could create. The management of the overall corporation, and therefore of the transmission function, would necessarily be reporting to a Board of Directors with a fiduciary duty to maximize returns for the corporation as a whole, including its generation operations, which poses a clear conflict of interest with the System Operator's obligation to ensure proper market function. The System Operator's Code of Conduct will require that it not favor generation from its affiliate.

The MDC recommended a Governance Panel to give the System Operator function some independence from the management of the Transco owner. The management of the System Operator would be responsible to the Governance Panel on all matters relating to the market. The MDC still had concerns with the degree of independence afforded by this model.

Recommendation 3-7. The MDC recommends that, if the System Operator is part of a corporation that owns generation resources in New Brunswick, it should report with respect to its market functions to a Governance Panel that is separate from the corporation's Board of Directors.

Market functions include:

- ***Making and revising the market rules;***
- ***Operating the bilateral contract market;***

- ***Operating the balancing market;***
- ***Market monitoring and market surveillance;***
- ***Operating the system including scheduling generation dispatch.***

Employees performing System Operator functions have primary reporting responsibility to and are accountable to the Governance Panel, and

- ***The Governance Panel are not employees of the System Operator;***
- ***Panel members are chosen as experts by government;***
- ***Panel members must be independent of participants in the New Brunswick electricity market [2: 2.1.2]***

The System Operator must also be accountable both financially and for its function. Since the regulator, the New Brunswick Board of Commissioners of Public Utilities (PUB) will in any case regulate the transmission system owner, it can readily also be the locus of accountability for the System Operator is therefore consistent with its other roles. The MDC adopted the following recommendation.

Recommendation 3-8. The MDC recommends that the System Operator be subjected to an independent audit with regards to the application of the market rules and tariffs as directed by the PUB. The terms of reference for the audit and selection of the auditor will be the responsibility of the PUB.[2: 2.1.2]

3.3.2 System Operator Roles and Responsibilities

Three entities are largely responsible for the operation of the electricity market. They are the System Operator, the transmission owner and operator (if different from the System Operator) and the regulator. Among these three, some roles and responsibilities can be allocated in different ways.

The first concern of a System Operator is with the security and reliability of the electricity system. To ensure system security, the System Operator must have the authority to direct its operation, though it might not directly operate any of the system elements.

Many other roles and responsibilities could be given to more than one of the three entities mentioned. The MDC discussed these options, and made recommendations on the assignment of roles and responsibilities for the System Operator in several areas. These are the System Operator's roles in relation to the routine operation of the market, market surveillance, compliance monitoring, licensing, market rules, the role of the System Operator in relation to any Regional Transmission Organization (RTO), and complaints and dispute resolution.

Routine Operation of the Market

To operate the bilateral contract market as the MDC has defined it, the System Operator must have a wide range of roles, responsibilities and functions. The MDC discussed and agreed on a list of roles and responsibilities with respect to the operation of the market. The MDC adopted two recommendations in this regard, one with respect to roles and one with respect to responsibilities. Both recommendations list broad categories.

Recommendation 3-9. The MDC recommends that the System Operator be given the following roles:

- ***Recorder and publisher of information (load, system requirements, system capabilities, etc.)***
- ***Planner (system expansion, etc.)***
- ***Setting requirements (metering, performance, etc.)***
- ***Administrator (tariff, settlement, etc.)***
- ***Facilitator (bilateral contracts, etc.)***
- ***Decision maker (transmission expansion, etc.)***
- ***Representative of Maritime Control Area (in NPCC, NERC, etc.)[2: 2.2.7]***

Recommendation 3-10. The MDC recommends that the System Operator be given the responsibility to:

- ***Ensure system reliability;***
- ***Implement and administrate open access transmission;***
- ***Administer a bilateral market for electrical energy;***
- ***Interface with other system and market operators;***
- ***Act as an operating authority for the generation and transmission system.[2: 2.2.7]***

For the System Operator functions, the MDC adopted both a recommendation listing the functions in general and an appendix with more detail on each of the functions. The recommendation is shown here.

Recommendation 3-11. The MDC recommends that the System Operator perform the functions of:

- ***After-the-fact administrator of system, tariff, and market;***
- ***Real-time System Operator;***
- ***Before-hand administrator of system, tariff, and market;***

- ***Short-term system planner;***
- ***Long-term system planner;***
- ***Development and submission to PUB of the transmission and ancillary services tariff.[2: 2.2.7]***

Market Surveillance

Market surveillance entails gathering and analyzing information with respect to both market power and market functionality.

Market power is the ability of one or more market participants to raise the market price by a significant amount and to sustain that increase to increase their profitability. Market functionality measures whether the market is working.

The *White Paper* indicated that three entities would have a role in market surveillance: the PUB, the Competition Bureau, and the System Operator. It stated directly that

> "…the Province will give the Board the authority to monitor the competitiveness of the wholesale market and ensure that the Crown utility is unable to exercise market power. This role is likely to be in coordination with the Competition Bureau and the System Operator who will have real-time data necessary to oversee the behaviour of market participants."[6]

This gave the PUB the primary role in market surveillance. However, it is also clear that the System Operator will have most of the data necessary to perform market surveillance. The MDC discussed whether the System Operator should undertake any independent analysis of these data, or should only react to data requests from the PUB. The MDC felt that the System Operator should be making periodic public reports on the functioning of the market. Those reports would be general and would not disclose any confidential data. The MDC also felt that the System Operator should be monitoring and reporting to the PUB, on an exceptions basis, information it gathered on the functioning of the market.

The MDC discussed handling and transferring confidential data by the System Operator. The Committee agreed that the market rules should have a policy statement on confidentiality. The statement would define what data are confidential, how they are to be treated, and how they are to be shared among the responsible agencies.

The result of these discussions was the following recommendations.

Recommendation 3-12. The MDC recommends that the System Operator be given the authority and the responsibility to provide information (including confidential

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[6] *White Paper,* pg. 27

information) as requested by the PUB in its role of monitoring the competitiveness of the New Brunswick market with respect to both market power and market functionality.[2: 2.2.1]

Recommendation 3-13. The MDC recommends that the System Operator be given the authority and the responsibility to release information that is not confidential to the public in a non-discriminatory, open access, same-time fashion.[2: 2.2.1]

Market Monitoring

To implement the market, there will be a set of market rules. The rules will define the precise responsibilities of all market participants. For the rules to be effective, some agency must monitor observance. Potential agencies include the System Operator, the PUB, or some other agency specifically created for this purpose. Since the System Operator is the agency at the center of the market, interacting constantly with market participants, it will have the information needed to monitor compliance.

The System Operator will be continuously monitoring the market for violations of the market rules. Many violations of the market rules are expected to be technical, which may be subject to summary penalties (fines, etc.). The System Operator should have the authority to impose penalties for minor offenses related to violations of the market rules. These penalties can be appealed to the PUB.

These considerations are set out in the following recommendations from the MDC.

Recommendation 3-14. The MDC recommends that the System operator be given the authority to:

- ***Monitor compliance of the market participants to the market rules;***
- ***Document non-compliance and make this information available to the PUB, as requested by the PUB; and***
- ***Apply penalties and sanctions as per the market rules.[2: 2.2.2]***

Licensing

The primary responsibility for licensing rests with the PUB. It is expected to set license conditions, issue the licenses, and administer the licensing system. The System Operator will have to be able to exclude unlicensed entities from participating in the New Brunswick market. The following recommendation gives it that authority.

Recommendation 3-15. The MDC recommends that the System Operator be given the authority and the responsibility to disallow entities from participating in activities in the New Brunswick market for which they are not licensed.[2: 2.2.3]

Market Rules

The *White Paper* charged the Market Design Committee with developing the "design, structure and rules"[7] of the electricity market. Many of the rules and operating protocols will be defined in the transmission tariff. The entity responsible for filing the tariff will be the NB Power transmission unit, which will draft the elements of market rules included in the tariff. By virtue of its authority and responsibility to approve the transmission tariff, the PUB will have oversight of these aspects of behavioral rules.

The entity in the market most involved in the market rules will be the System Operator. Because of its centrality to the market, it will be the agency for changes in the rules, when necessary.

Recommendation 3-16. The MDC recommends that the System Operator be given the authority and the responsibility to issue, update and maintain the market rules.[2: 2.2.4]

The market rules affect market participants, who should have input into any changes. In addition to market participants, the interests of other groups such as environmental advocacy groups and consumers could be affected by changes in the market rules. They should therefore also have input into the change process.

After some discussion, the MDC recommended a Market Advisory Committee as the mechanism for stakeholder input. It is the first step in both the market rule change process and in dispute resolution with respect to the market rules.

The first recommendation deals with the establishment and roles of the Committee, the second with its membership, and the third with dispute resolution in relation to changes in the market rules.

Recommendation 3-17. The MDC recommends that a Market Advisory Committee be created to advise the System Operator on matters including:

- ***Changes to the market rules;***
- ***Issues with respect to System Operator functions in relation to the market;***
- ***Issues with respect to market monitoring and market surveillance;***

and furthermore, that:

- ***Issues can be brought to the Market Advisory Committee by members, by the System Operator, or by other interested parties;***

[7] *White Paper,* pg. 14

- ***The Market Advisory Committee will recommend changes in the market rules to the Board of Directors of the Independent Transco System Operator Board or the Governance Panel of the System Operator function, as the case may be;***
- ***The Market Advisory Committee will make other recommendations to the System Operator Board or Governance Panel. [2: 2.2.4]***

Recommendation 3-18. The MDC recommends that the Market Advisory Committee should be a standing committee composed of representatives of market participants, stakeholders, and the System Operator.

Representatives will be chosen in three ways:

- ***Each registered market participant group will have representatives chosen by voting within the group;***
- ***Designated stakeholder groups (e.g., consumers, environmental advocacy groups) will have representatives chosen by Government;***
- ***Representatives of the System Operator will be chosen by the Board of Directors of the Independent Transco or the Governance Panel of the System Operator, as the case may be. [2: 2.2.4]***

Recommendation 3-19. The MDC recommends that:

- ***The System Operator, as advised by the Market Advisory Committee, will have the authority to propose and implement changes in the market rules;***
- ***Any market participant or stakeholder who objects to the changes must, in the first instance, raise their objections with the Market Advisory Committee;***
- ***If the response of the Market Advisory Committee is unsatisfactory to the market participant or stakeholder, an appeal may then be made to the Board of Directors of the Independent Transco or Governance Panel of the System Operator, as the case may be;***
- ***Having not received satisfactory remedies from within the System Operator organization, the market participant or stakeholder can then appeal to the PUB.[2: 2.2.4]***

Regional Transmission Organization

As a result of recent FERC orders, markets in the United States are being amalgamated into large Regional Transmission Organizations (RTOs). New York and New England have begun discussing formation of their own RTO. The *White Paper* directed the Crown utility to discuss forming an RTO with neighboring jurisdictions. New Brunswick has been involved in discussions with various potential participants in an RTO. The directive from the *White Paper* is still relevant, therefore.

Talks to date on forming a large RTO in the Northeast have been between system/market operators. The logical representative for New Brunswick to these RTO discussions is therefore the System Operator, which will be responsible for administering the market whether or not New Brunswick joins the RTO.

Recommendation 3-20. The MDC recommends that the System Operator be given the authority and the responsibility to:

- ***Continue discussions with neighboring jurisdictions to enhance the overall level of access among these systems;***
- ***Present options and recommend decisions with respect to participation in an RTO or similar organization to the Minister of Natural Resources and Energy;***
- ***Consult as well as brief stakeholders on the process of participating in such an arrangement. [2: 2.2.5]***

Complaints and Dispute Resolution

Several areas of application in the electricity market could give rise to disputes. Two separate dispute resolution mechanisms may be needed for the System Operator and the transmission owner and operator. The obvious locus for resolving disputes relating to the transmission owner and operator is with the PUB, because it will have jurisdiction over the transmission tariff, including the code of conduct.

The first steps in resolving any dispute between market participants and the System Operator should be internal to the System Operator. Only after exhausting internal mechanisms should the dispute go outside the System Operator, when it would be taken to the PUB. The MDC did not adopt a specific recommendation on such a process. It did note that the process for resolving disputes relating to the System Operator's application of the market rules and other disputes between the System Operator and market participants should be spelled out in the market rules.

3.4 Market Design to Ensure Reliability

Ensuring "a secure, reliable, and cost effective energy supply" is a primary policy objective expressed in the *White Paper*. In the *White Paper* the Government directed the MDC "to consider reliability of supply for New Brunswick in its market design recommendations."

The MDC reviewed an Issues Paper on reliability. There are two primary aspects of power system reliability: (1) the security of supply; and (2) sufficient generation and transmission resources to ensure an adequate supply of power to customers.

3.4.1 System Security

The security of supply is an operations issue. System security rules and procedures are specified by the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC) and standards need not change because the market structure changes. Therefore, the MDC needs only to make decisions regarding who will be responsible for maintaining system security, but does not need to make decisions regarding these rules and procedures. NB Power Transmission serves in this role under the current market structure. Under the new market structure the most obvious candidate for these responsibilities is the System Operator.

To allow it to fulfill these functions the Market Design Committee makes the following recommendation.

Recommendation 3-21. The MDC recommends that the System Operator will have the responsibility and authority to ensure system security. To accomplish this, it will be empowered to:

- ***Maintain system security within criteria as set by NERC and NPCC or other responsible standards body;***
- ***Determine security requirements for the New Brunswick system;***
- ***Procure and provide ancillary and security services;***
- ***Represent New Brunswick at committees of NERC and NPCC or other responsible standards bodies;***
- ***Provide, under a FERC Order 888 compatible OATT, ancillary services required for system security;***
- ***If necessary for system security:***
    - ***Cause any generator to inject or not to inject electricity or any load to withdraw or not to withdraw electricity into or from the system;***
    - ***Cause any transmission owner to operate or not operate its transmission system;***
- ***Perform any other functions necessary to ensure system security.[2: 2.3.1]***

3.4.2 Adequacy of Supply

Any electricity system needs reserve capacity for unanticipated peak loads and capacity outages if it is to ensure a reliable supply for customers. While operating reserve is used to mitigate the impacts of the next outage, installed capacity in excess of forecasted peak firm load accounts for the combined effect of generation outages as well as abnormally high peak loads due to extreme weather and major transmission outages. The capacity in excess of the forecast firm load is often referred to as planning reserve[8]. In New Brunswick there is currently an installed capacity requirement of 120 percent of the projected peak firm load. This criterion roughly corresponds to a reliability standards target of having sufficient generation to assure generation adequacy-related outages occur no more frequently than one day in ten years.

The Committee determined that continuing to participate in NERC and NPCC and adhere to their standards is an important element of assuring continuation of historic reliability. It was determined that vesting the organizational responsibility for adequacy of supply with the System Operator best balanced the objectives of ensuring accountability, independence and flexibility.

The following recommendation was made to enable the System Operator to be able to evaluate capacity adequacy.

Recommendation 3-22. The MDC recommends that the System Operator have responsibility and authority to ensure that an adequate level of capacity is available in the New Brunswick market. To accomplish this, it should be empowered to:

- ***Determine NB market system installed capacity requirement;***
- ***Monitor available and committed capacity;***
- ***Project future capacity surpluses and deficits;***
- ***Publish periodic reviews (e.g., 18 month and 10 year);***
- ***Report to NPCC and NERC;***
- ***Assess penalties for shortages;***
- ***Review capacity criteria;***
- ***Receive and monitor information from market participants on their capacity provided to the market;***
- ***Propose changes to capacity ratings system (based on forced outage history) if deemed necessary in the future;***
- ***Verify Dependable Maximum Net Capacity (DMNC) ratings for capacity providers; and***
- ***Perform other related functions as necessary to provide for capacity adequacy.[2: 2.3.2]***

[8] The NERC glossary defines planning reserve as "Planning Reserve: The difference between a Control Area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand."

Once the System Operator has determined the level of capacity required to maintain system reliability, there are three basic strategies for providing for an adequate supply of capacity: (1) relying solely on market price signals and establishing no enforced capacity requirement; (2) establishing a capacity requirement with bilateral contract market; and (3) establishing an installed capacity (ICAP) market operated by the System Operator. Each of these approaches is discussed in depth in Issue Paper #7: Reliability Issues.

Recognizing the importance of capacity adequacy to the performance of the wholesale power market, there was a general consensus among the MDC that market participants should be required to provide sufficient installed capacity to ensure system reliability.

Recommendation 3-23. The MDC recommends that all market load participants in New Brunswick have the obligation to:

- ***Provide capacity:***
  - ***Equal to their load ratio share of the system installed capacity requirement;***
  - ***Based on the projected peak load; and***
  - ***Subject to penalty for under supply, determined ex post.***
- ***Cause to be reported to the System Operator continuously operational parameters and availability of the capacity including:***
  - ***DMNC ratings;***
  - ***Deratings and forced outages;***
  - ***Maintenance schedules; and***
  - ***Daily and seasonal operational schedules.***
- ***Capacity responsibility of a load entity can be administered on its behalf by other market participants. [2: 2.3.2]***

Installed capacity located outside of New Brunswick can contribute to the reliability of the New Brunswick system, as indicated in the recommendations below.

Recommendation 3-24. The MDC recommends that any firm capacity for supply in New Brunswick which qualifies as accredited capacity under NERC and NPCC rules be eligible to provide required capacity:

- ***Such capacity must be certified by the System Operator***
  - ***Initially when constructed and then***
  - ***On some periodic basis;***
- ***Such capacity can be acquired by building generation and/or purchasing installed capacity (ICAP);***

- ***Such capacity can be acquired from outside NB if it***
    - ***Is supported with firm transmission for delivery to NB; and***
    - ***Meets accredited capacity requirements.[2: 2.3.2]***

Recommendation 3-25. The MDC recommends that capacity suppliers in the New Brunswick market have the following responsibilities:

- ***They must notify the System Operator if they are not available;***
- ***If available, they must supply energy and/or ancillary services if called upon by System Operator.***

Penalties would apply for failing to provide if called upon and available.[2: 2.3.2]

3.4.3 Market Structures to Assure Transmission Adequacy

One goal identified in the *White Paper* was to assure continued reliability of the bulk power system. Achieving this goal requires continuation of the transmission adequacy criteria employed today.

The MDC recommended that the System Operator be vested with the authority and responsibility to ensure transmission adequacy. To accomplish this the MDC made the following recommendations.

Recommendation 3-26. The MDC recommends that the System Operator have the authority and responsibility for ensuring transmission system adequacy in the New Brunswick market. To accomplish this, it should be empowered to:

- ***Set transmission adequacy criteria, having regard for standard criteria in interconnected systems;***
- ***Study future transmission and generation systems in New Brunswick and adjacent market areas and conduct system studies to determine if additional transmission is required;***
- ***Publish periodic reviews (tri-annual as minimum);***
- ***Report to NPCC and NERC;***
- ***Review planning criteria and change the criteria if necessary;***
- ***Consult with transmission owner(s) to set interconnection standards;***
- ***Perform system studies for proposed new generation or load connections to determine if new transmission is required;***
- ***Request and receive proposals for potential solutions from***

  - ***Transmission***
  - ***Generation***
  - ***Demand Side***
- ***Evaluate proposals using criteria including environmental impact; and***
- ***Perform other related functions necessary for transmission adequacy.[2: 2.3.3]***

Transmission Construction

As part of its long-term planning function, the System Operator will be charged with ensuring that there is adequate capacity in the system. Transmission is a crucial element of the system and will continue to be a regulated monopoly.

To reinforce the System Operator's role with respect to system adequacy, and to ensure that the System Operator could address transmission needs if necessary for the operation of the market, the MDC adopted the following recommendation.

Recommendation 3-27. The MDC recommends that the System Operator be given the responsibility and authority to cause new transmission to be constructed if necessary for system adequacy or efficient operation of the market. If the transmission owner will not build the transmission, the System Operator can contract for its construction and ownership with a third party. [2: 2.2.8]

Since the System Operator may not own transmission assets the transmission owner must coordinate with the System Operator and have responsibilities for ensuring the adequacy of the transmission system. To ensure this coordination between the System Operator and the transmission owner, the MDC made the following recommendation.

Recommendation 3-28. The MDC recommends that transmission owners have the following responsibilities:

- ***Provide transmission system operating information to the System Operator;***
- ***Operate the transmission system under direction of System Operator;***
- ***Comply with tariff requirements;***
- ***Comply with code of conduct requirements;***
- ***Consult with the System Operator to set interconnection standards; and***
- ***Comply with procedures and protocols, set by the System Operator, which are necessary for transmission adequacy and security.[2: 2.3.3]***

3.5 Ancillary Services

3.5.1 Energy Imbalances

In the New Brunswick market, all market participants must file balanced schedules energy with the System Operator. Energy imbalances arise when the actual amounts injected or withdrawn differ from those scheduled. Given the uncertain nature of electricity supply and demand, some level of inadvertent imbalance is inevitable. The System Operator must be able to keep the system in balance, and it typically does so through the use of such ancillary services as automatic generation control.

In an effort to use the energy imbalance service as a move towards a market, the MDC recommended treating energy imbalances as a market-based service, with the following recommendation.

Recommendation 3-29. The MDC recommends that the System Operator shall operate an energy imbalance service. The System Operator can procure energy imbalance service from market participants, buying at the lowest available price within operating constraints. The energy imbalance service shall be priced at a proxy value recognizing cost and could move towards market-based pricing. The purpose is to encourage development of an efficient and effective service.[1: 3.3.2]

The MDC recognized that energy imbalance requirements could not create a true real time market. The amount of energy to be settled would be small.

During Phase 3, the MDC looked more closely at the physical and operating mechanisms for such a market, realizing that it would be more limited than first envisioned. The Committee concluded that it preferred to recognize the limitations, but to recommend moving towards a market if possible, as indicated in the following recommendation.

Recommendation 3-30. The MDC recommends that balancing energy service be initially provided as an ancillary service through the transmission tariff and that its provision be based on the following principles:

- ***It should efficiently provide economic signals that will drive behaviours appropriate for reliable operation of the system;***
- ***Pricing of the service should be market-based where possible through:***
  - ***Offers for increments and decrements***
  - ***A proxy market price***
  - ***Ceilings and floors as necessary to protect participants.[3: 2.2]***

3.5.2 Other Ancillary Services

Several other ancillary services must be provided to make the bilateral contract market work. When transmission and distribution tariffs are separated from energy costs, ancillary services costs must also be unbundled. In the bilateral contract market, the System Operator will offer all the ancillary services. Aside from energy imbalance service, the major ancillary services are:

- Operating reserves;
    - Ten-minute spinning reserve
    - Ten-minute non-spinning reserve
    - Thirty minute reserve
- Regulation or AGC (Automatic Generation Control), the ability to vary output quickly in response to a signal from the System Operator;
- Reactive support, the maintenance of system voltages within required levels;
- Black start, the ability to restart the system after a system-wide outage.

To help develop the market, the MDC decided that ancillary services should be purchased on a competitive basis where possible and where the costs of the competitive purchase process are not excessive.

Recommendation 3-31. The MDC recommends that ancillary services shall be provided by the System Operator, with tariffs approved by the PUB and subject to an audit. The System Operator will procure the contract ancillary services from the market participants at least cost possible, including by competitive contract processes.[1: 3.3.3]

3.6 Reciprocity

Recognizing that reciprocity requirements have significant implications for the competitiveness of the New Brunswick market and could affect the risks associated with stranded cost recovery, the *White Paper* directed the MDC "to examine and make recommendations regarding the need for reciprocity requirements in its design of the New Brunswick market."[9]

Reciprocity can help with two objectives: opening export markets so domestic producers can compete there, and creating more competition in domestic markets by allowing producers from other markets to enter.

[9] *White Paper*, pg. 38

Reciprocity is a cornerstone of the U.S. Federal Energy Regulatory Commission's (FERC) Order No. 888. FERC mandated reciprocity to ensure that all transmission systems, including those exempt from its jurisdiction, opened their transmission systems under consistent terms and conditions. FERC's authority to impose market reforms in the U.S. has no parallel in Canada. Canada's closest federal equivalent, the National Energy Board (NEB), has very limited authority over electricity policy compared to that of the individual provinces. It is likely that a number of provinces will continue to base electricity policy decisions more on provincial self-interest than on broader regional interests.

If a province expects economic gain from increased electricity trade with U.S. or Canadian markets, it is likely to make sure it meets at least their minimum reciprocity requirements. So reciprocity will continue to be an effective lever to promote greater opening of some markets.

Two jurisdictions where reciprocity might create an opportunity for New Brunswick are Quebec and Nova Scotia. Neither province has opened or presently proposes to open its retail markets to the level called for by the New Brunswick *White Paper*. Therefore, if New Brunswick were to require an equivalent level of access it could exclude generators in both provinces from the New Brunswick market.

While reciprocity can be used to preclude access to utilities that do not provide an equivalent level of access, it will not necessarily prevent the power available from these utilities from ultimately being sold in New Brunswick through marketers, traders or retailers who buy at the border. Therefore, a reciprocity provision is not likely to represent a major foregone opportunity to these utilities or to New Brunswick consumers. However, it would likely result in fewer possible competitors in New Brunswick.

In summary, the MDC concluded that a reciprocity provision is not likely to be effective in inducing Quebec and Nova Scotia to provide an equivalent level of access as is being pursued in New Brunswick. However, if enforced it could reduce the number of possible suppliers available to New Brunswick customers. Furthermore, there are no major stranded cost risks if an exit fee is imposed on customers that create such stranded costs.

Therefore, to increase the possibility of more suppliers and hence the prospects for achieving a workably competitive market and provide greater opportunity for customers to obtain competitive prices, the Market Design Committee adopted the following recommendation.

Recommendation 3-32. The MDC recommends that reciprocity not be a requirement for participation in the New Brunswick retail markets at this time. The System Operator shall have the authority to invoke any reciprocity provisions in the Open Access Transmission Tariff that it administers.[2: 2.4]

4 STANDARD OFFER SERVICE

The mechanism envisioned in the *White Paper* to protect customers that are not eligible to choose an alternative supplier and those that do not choose an alternate supplier will be the Standard Offer Service (SOS). The *White Paper* said that such customers should be entitled to "standard offer service under regulated prices and terms that are consistent with the service they now obtain."[10] The issues associated with the provision of standard offer service are among the most important in determining price of the service and the competitiveness of New Brunswick wholesale and retail markets.

4.1 MDC Process

The MDC discussed the issue of SOS extensively. The discussion began with Issues Paper #6: Standard Offer Supply.

Some aspects of SOS supply in the models the Committee considered will be impacted by the corporate organization structure of NB Power or its successors. *The Committee therefore felt that its discussion of these aspects was hampered, since the future structure of NB Power was not known.*

4.2 Models for Provision of Standard Offer Service in New Brunswick

The system for provision of SOS in New Brunswick must perform several functions. How it does that can be an important determinant of the speed of movement towards competition in the province.

After some discussions of various models of SOS supply, the MDC focused on consideration of two models, called for discussion purposes Model A and Model B. These two models evolved from the several which had been introduced.

The two models had many features in common. Both rested initial supply for SOS service on the concept of a Heritage Pool of existing assets, electricity from which would be sold under vesting contract(s). They both continued to assign to the local distribution utility serving the geographical areas responsibility for retail connections and energy supply to their customers at a cost-based rate. Both provided that there be a market for new supplies of capacity and energy.

The requirements placed on an entity which was described for conceptual purposes as NB Power Genco[11] were the same in both models. NB Power Genco would be obliged

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[10] *White Paper*, pg. 34

[11] The MDC assumed that NB Power would be at least functionally unbundled into a generator, a transmission function, and a distribution function. In the consideration of SOS supply, the MDC assumed that the customer service functions of NB Power will remain with the distribution function, which was characterized as NB Power Disco.

to deliver the amount of capacity and energy represented by the Vesting Contract(s) at the regulated price. Both models returned unused energy from the Heritage Pool to NB Power Genco for sale elsewhere.

The models differed, however, in identifying the counterparties for the basic supply contracts and in how long the obligation to provide SOS lasts.

In Model A, NB Power Genco would contract directly with each customer eligible to participate in the bilateral contract market. In Model B, it would contract only with an SOS supplier (described in the Second Interim Report as NB Power Disco).

New supply could be required either to deal with load growth or as a result of assets being removed from the Heritage Pool. The models differed in their approach to obtaining new supply. Under Model A, when new supply is required the eligible customers (including NB Power Disco) would have to contract for it individually. In Model B, the SOS supplier would contract (through a supervised RFP process) on behalf of all customers.

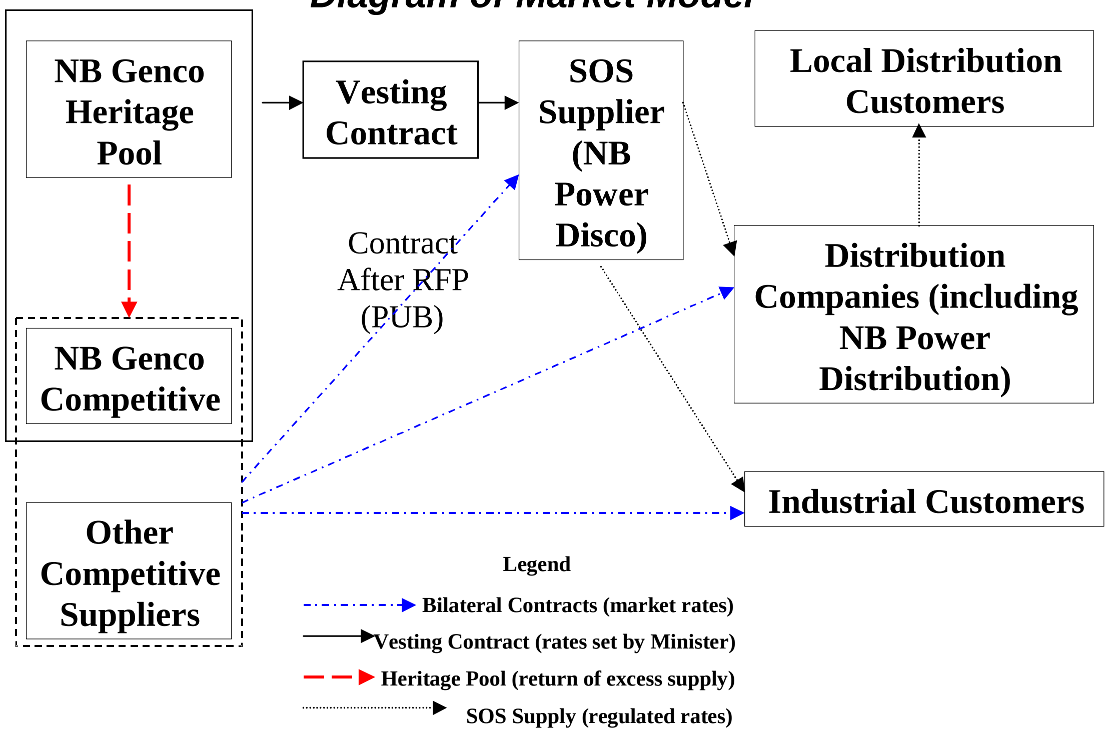
After new supply is required, therefore, customers would be paying a blended (old and new) price under both models. In Model A, each contestable customer would be responsible for the price of its new supply, while in Model B the price would be determined collectively. The result would be that each customer’s actions would have a more direct effect on its own effective electricity acquisition cost under Model A, while under Model B the customer acquisition cost would be determined collectively.

The MDC compared the two models along many dimensions, including the criteria adopted in Issues Paper #1: Criteria for Decisions. It analyzed how each model would perform the vital functions of the market.

Concern for the protection of customers through continued access to regulated rates was weighed against the risks of introducing new stranded costs and of discouraging new supplies. After much discussion, the MDC indicated that it would pursue development of Model B. In subsequent discussions, the MDC further refined both the model and its ideas on the Heritage Pool and the Vesting Contract. A diagram of the adopted model is given below in Figure 1.

Figure 1

Diagram of Market Model



To adopt the model, the MDC made the following recommendation. Some members of the MDC dissented from the model choice and some abstained from choosing one model over another.

Recommendation 4-33: The MDC recommends that Standard Offer Service:

- ***Be provided by the SOS supplier to all customers who decide not to choose or are unable to choose an alternative supplier;***
- ***Be offered at rates based on the SOS supplier's blended cost of providing that service;***
- ***In the first instance, be obtained by the SOS supplier from the Heritage Pool at a price to be established by the Minister;***
- ***Insofar as insufficient energy or capacity is available from the Heritage Pool be obtained through an RFP issued by the SOS supplier;***

and further that:

- ***NB Power Disco make public independently audited annual statements that demonstrate that all SOS supply to its own distribution system is priced the same as to other distribution systems.[2: 3.4]***

4.3 Heritage Pool

The Heritage Pool is a mechanism for isolating the assets of the existing system, which resulted from past decisions under an older regime, from those obtained under a new market regime. The Heritage Pool was conceived of as an amount of electricity that could be delivered by the existing NB Power generation assets. These assets were called "Heritage Assets" because they exist at the start of the competitive market. The recommendation on SOS (4-33above) supply uses, but does not define, the term Heritage Pool.

The MDC defined the Heritage Pool as the capability of the existing generating assets and purchase contracts to deliver power and energy to consumers in New Brunswick.

Recommendation 4-34. The MDC recommends that the Heritage Pool be defined initially as the quantity of energy and capacity determined by the capability of the generation assets existing in 1999 to supply all in-province load at a system load factor of 61%. [3: 2.1.2]

This definition leaves open the question of the change in size of the Heritage Pool over time. The MDC has been clear that the Heritage Pool obligation diminishes as the underlying assets are retired. It had also discussed the concept that assets requiring major refurbishment in lieu of retirement would come out of the Heritage Pool, and the delivery obligation of NB Power Genco to the SOS supplier would diminish correspondingly.

Within the Heritage Pool, all the assets and all their costs are pooled. Therefore, if plants are included in the Heritage Pool after major capital expenditures for refurbishment, then the capital cost will be included with all the other costs of the Heritage Pool assets, and recovered as part of the supply delivered under the Vesting Contract. If refurbished facilities are not in the Heritage Pool both sellers and buyers will be forced to contract on the competitive market.

The following recommendation preserves the idea that assets facing retirement should be removed from the Heritage Pool, whether they are retired or refurbished.

Recommendation 4-35. The MDC recommends that, as assets retire, or require major capital expenditure in lieu of retirement, their capacity is removed from the Heritage Pool. [3: 2.1.2]

During its discussions on the Heritage Pool, the MDC focused on two current NB Power plants facing major capital expenditures. NB Power is in the process of applying for approvals for conversion of Coleson Cove and refurbishment of Point Lepreau. The MDC discussed the implications of whether one, both, or neither of these plants would be included in the Heritage Pool if these major capital expenditures are incurred.

Since the Coleson Cove expenditure is not considered to be in lieu of retirement, it would be included in the Heritage Pool under the definition in Recommendation 4-35 above. At issue, therefore, is Point Lepreau.

The following recommendation is consistent with the expectation that the Minister will review the New Brunswick market, and will be able to decide in the future whether or not to include specific assets in the Heritage Pool.

Recommendation 4-36. The MDC recommends that the Minister decide prior to a commitment for refurbishment of Point Lepreau in lieu of retirement whether it will be included or excluded from the Heritage Pool.[3: 2.1.2]

Another alternative discussed was the removal of a specified amount of assets from the Heritage Pool. The amount removed and the timing could be linked to an expected physical event, like the refurbishment of Point Lepreau. The MDC suggested that, if Point Lepreau is included in the Heritage Pool after refurbishment, the Minister consider decreasing the Heritage Pool by a fixed amount that is close to the capacity of Point Lepreau. This would help to promote a competitive electricity market in New Brunswick. For example, the Minister could consider reducing the Heritage Pool by 200 MW every other year for six years, to reach a total reduction of 600 MW.

4.4 Terms of the Heritage Pool Vesting Contract

Figure 1 shows that the vehicle for the delivery of the Heritage Pool supply to the SOS supplier is a vesting contract. The Vesting Contract will be between NB Power Genco and the SOS supplier.

The MDC discussed three aspects of the Vesting Contract: whether the SOS supplier has an option or an obligation for the Heritage Pool amount, what is the disposition of any capability in excess of the in-province load, and prices for supply under the contract.

4.4.1 Obligation of the SOS Supplier

The risk could all be placed on the SOS supplier by making the Vesting Contract take or pay. On the other hand, the contract could specify the Heritage Pool amount as an option. To protect the owner of the assets, the SOS supplier should be subject to the same exit fee requirement as other customers.

After some discussion, the MDC decided that the generator would have the risk of low demand, while the SOS supplier is responsible for stranded costs it causes. It approved the following recommendations, which treat the SOS supplier in a way consistent with other contestable customers.

Recommendation 4-37. The MDC recommends that a Vesting Contract be put in place between NB Power Genco and the SOS supplier. Such a contract will specify that the SOS supplier has an option to acquire supply from the Heritage Pool assets up to their defined capability.[3: 2.1.3]

Recommendation 4-38. The MDC recommends that the obligation on the SOS supplier to take power from the Heritage Pool assets is the same as that on any other contestable customer; it pays an exit fee if it creates stranded costs.[3: 2.1.3]

4.4.2 Disposition of Excess Supply from the Heritage Pool

The SOS supplier is not expected always to need the full amount of supply available from the Heritage Pool. The Heritage Pool amount is in excess of anticipated demand for at least the first years of the market. The Vesting Contract does not obligate the SOS supplier to take the full amount of Heritage Pool supply. Current practice is to sell such surplus supply in adjacent markets. Figure 1 shows that power from the Heritage Pool in excess of needs under the Vesting Contract is returned to NB Power Genco for sale in the competitive market.

The MDC adopted the following recommendation to make clear that it recommends that NB Power Genco could continue to sell surplus supply.

Recommendation 4-39. The MDC recommends that any amount of supply from the Heritage Pool assets which is in excess of current SOS supplier needs can be sold by NB Power Genco in the market. [3: 2.1.3]

4.4.3 Pricing the Vesting Contract

Recommendation 4-33 gives the Minister the responsibility for pricing the Heritage Pool amount under the Vesting Contract. The MDC decided that an incentive-based form of regulation would be appropriate for pricing the Vesting Contract.

Such an approach would set changes in price according to a formula. The formula would take into account the impact of fuel price changes on generation costs, the general rate of input price increases for other resources used in generation (labor, other materials, etc.), and an incentive to improve productivity. The resulting price formula would be similar to the Performance Based Regulation formula currently being widely applied for regulated wires (transmission, distribution) utilities in competitive markets.

If there is to be a form of performance-based pricing for the Vesting Contract amounts, some entity must be responsible for monitoring its administration. As with the initial pricing, the MDC felt that the government must monitor and control these prices directly on an ongoing basis. The Committee did not expect that such monitoring would impose an undue burden on either the government or NB Power Genco.

These decisions are reflected in the following recommendation.

Recommendation 4-40. The MDC recommends that the Vesting Contract price for supply from NB Power Genco to the SOS supplier, beyond the initial price set by the Minister, be under a form of incentive regulation (similar to performance-based

regulation), to be administered by the Minister, for changes after the initial period.[3: 2.1.4]

The *White Paper* says that “The Province will direct the Crown utility to produce and file time-of-use rates with the Board [PUB] by autumn 2002.”[12] Since in the initial years at least the Vesting Contract will likely supply a large fraction of their total needs, the distributors would have difficulty arriving at a cost base for time-of-use pricing unless the Vesting Contract is priced on a time-of-use (or at least seasonal) basis. To encourage that kind of pricing, the MDC adopted the following recommendation.

Recommendation 4-41. The MDC recommends that the Vesting Contract consider time-of-use pricing.[3: 2.1.4]

The MDC also noted the *White Paper* commitment to time-of-use pricing for retail customers, and adopted a recommendation relating to time-of-use pricing for the SOS supply.

Recommendation 4-42. The MDC recommends that SOS supply adopt an option to the customer for time-of-use pricing as soon as the supply under the Vesting Contract is priced on that basis.[3: 2.1.5]

4.5 Other Conditions of SOS Supply

4.5.1 SOS Duration and Rate Structure

Recommendation 4-33 implies that some form of standard offer supply will be available indefinitely. The vehicle for SOS supply at the start of the market will be the Vesting Contract between NB Power Genco and the SOS supplier. The SOS supplier will have one source of supply at first, but will have multiple sources as soon as load growth or asset removal from the Heritage Pool leads to the need for new supply.

Supply from the SOS supplier to its customers will be regulated, as specified in the *White Paper*. The MDC recommended that the SOS supply be offered at regulated rates based on the blended cost of providing the service. The blending refers to the combination of supply from the Heritage Pool and from the results of a request for proposal (RFP) processes undertaken by the SOS supplier.

The MDC noted that the SOS rates should be carefully designed. They should reflect the conditions of cost to the SOS supplier, including the costs of acquiring the reserve capacity required under the MDC’s Phase 2 reliability recommendation.

The rates for such supply will be proposed by the SOS supplier and approved by the PUB. For that reason, the MDC did not make any specific recommendations on this matter.

[12] *White Paper*, pg. 54.

4.5.2 Splitting Supply Sources

The MDC discussed whether or not to allow contestable customers to choose whatever portion of competitive supply and SOS supply best meets their needs.

Forcing contestable customers either to stay on SOS supply or go off it deters the customer from abusing the fixed-price SOS supply by switching frequently between it and competitive supply. It also simplifies billing. Finally, allowing split supply could create a burden for the SOS supplier by forcing it to supply only at the peak period, when generation is the most expensive.

On the other hand, there are several advantages to allowing contestable customers to split their supply sources. The most important of these is that not allowing split supply could become a serious deterrent to the development of competitive supply sources.

On balance, the MDC felt that not allowing eligible customers to split supply would inhibit the development of a competitive market, so it adopted the following recommendation.

Recommendation 4-43. The MDC recommends that contestable customers be able to procure both energy and capacity supply from the SOS provider, from the competitive market, or from any mix of these sources.[3: 2.1.6]

4.5.3 Leaving from and Returning to SOS Supply

When a customer leaves SOS supply, it may create conditions of stranded costs or stranded benefits. Under the principle of user pays, the *White Paper* states that the departing customer would pay as an exit fee any costs it imposes on the system.[13]

The SOS supplier is obligated to be able to supply all the needs of its customers. That obligation extends to growth in demand from old customers and to new customers. At issue is whether customers who had left should be able to return to SOS supply and if so should they be treated differently from other customers.

A policy that permits customers to exit and re-enter SOS supply can impose a burden on the SOS supplier because they are likely to leave when SOS prices are high and to return to SOS supply when SOS prices are below market.

One area of cost for the SOS supplier is the demand uncertainty. The supplier could carry enough capacity to serve returning load, and risk having an excess. Or, the supplier could not carry enough capacity, and risk a shortfall if the contestable loads return. Further, letting customers freely leave and return creates the risk that the SOS

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[13] The *White Paper* also asked the MDC to consider exit fees or other appropriate mechanism to recover these costs.

supplier will have insufficient capacity at times of high demand (and therefore high prices in the competitive market) and excess capacity at times of low demand (and therefore low prices in the competitive market).

These costs, associated with the right of customers to return to SOS supply, will be carried either by the owner of NB Genco (the Province) and thus paid for by taxpayers, or reflected in the Vesting Contract rates and thus included in the rates for SOS supply. The latter imposes a cost on those that choose not to leave standard offer, and on those that do not have an opportunity to leave. The imposition of this cost is inconsistent with the *White Paper* objective to "entitle all customers that do not select a competitive supplier to standard offer service under regulated prices and terms that are consistent with the service they now obtain."

The customer who leaves SOS supply should have left other SOS customers effectively neutral. If there is an appropriate structure in place to make exiting neutral, then there is no particular reason to treat returning customers differently from other new SOS customers.

Having the right to leave from and return to SOS supply too freely could create a problem of cost shifting, however. Even if they are based on time-of-use, the prices of the SOS supply are not likely fully to reflect variance in cost of generation over a year. A customer that could switch without penalty at any time could exploit the difference between the relatively fixed SOS price and the variable market price. One way to prevent it would be to restrict frequent switching between SOS and competitive supply.

Balancing these considerations, the MDC approved the following recommendations.

Recommendation 4-44. The MDC recommends that any new customer who wants to obtain SOS supply can do so under the same conditions as existing SOS customers.[3: 2.1.7]

Recommendation 4-45. The MDC recommends that a load leaving SOS is not eligible to receive service from the SOS supplier for 12 months. The SOS supplier has an obligation to supply any contestable customer that has left SOS for at least 12 months.

The principles for the provision of this service are:

- ***The pricing for this service should prevent cost shifting between existing SOS customers and returning customers;***
- ***The terms of this power supply agreement will be negotiated with the SOS supplier;***
- ***The price for this service should be based on the SOS supplier's cost; and***
- ***The SOS supplier's pricing for this service should be subject to regulatory review.[3: 2.1.7]***

4.6 Acquisition of Supply by the SOS Supplier

4.6.1 The RFP Process

Recommendation 4-33 specifies that the SOS supplier is required to use an RFP process for acquisition of supply beyond the Heritage Pool amount. The MDC was concerned for several reasons to ensure that the RFP process is open and fair. This concern is especially important if the SOS supplier is affiliated with a generator. It is also important to help prospective suppliers be confident that they have an equal opportunity to compete to supply the SOS supplier.

The Committee considered recommending specific processes for the acquisition of supply. All such mechanisms carried risks. Therefore, the Committee felt that it was inappropriate to prescribe guidelines regarding SOS supplier contracting practices.[14] Rather than stipulate the terms and conditions of such competitive supply processes, the MDC decided to delegate responsibility to the PUB.

Recommendation 4-46. The MDC recommends that the PUB be given authority to approve the SOS supplier's process and procedures with respect to RFPs for power supply for SOS. In doing so, the PUB will apply criteria of fairness and transparency. [3: 3.3.2]

Recommendation 4-47. The MDC recommends that the PUB be given authority to hear complaints regarding the process, procedures and content of the RFPs for power supply for SOS. [3: 3.3.2]

The MDC also discussed whether to limit NB Power's participation in any long term RFP process to limit its market power and promote competitive entry. Many members felt that preventing NB Power from participating could limit a lower cost supplier. Furthermore, there was a concern that at a minimum NB Power should have a role as "builder of last resort" to ensure the adequacy of supply for New Brunswick customers. Reflecting these concerns the MDC made the following recommendation.

Recommendation 4-48. The MDC recommends that NB Power Genco be required to offer capacity and/or energy in response to an RFP by the SOS supplier.[3: 3.3.2]

4.6.2 Offers to the SOS Supplier

At times other than when an RFP is issued, generators or other market participants may want to offer supply to the SOS supplier. The MDC felt that there should be no barrier to such an offer. The MDC therefore approved the following recommendation.

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[14] A decision to establish purchase guidelines would have been inconsistent with a subsequent decision by the MDC that the SOS service provider would have to bear all stranded cost risks for resources purchase commitments other than the Heritage Pool.

Recommendation 4-49. The MDC recommends that, at any time, any market participant can offer to the SOS supplier to supply energy or capacity to meet its SOS requirements.[3: 2.1.8]

5 REGULATOR ROLES AND RESPONSIBILITIES

The Board of Commissioners of Public Utilities (PUB) would have several responsibilities under the market design as recommended by the MDC. Many of these are contained in recommendations in previous and subsequent sections of this Final Report. In addition, the Committee established a working group to review the various other issues that the PUB may have to address as a result of the market structure reforms being evaluated. Issues addressed by the Working Group are reported in this section.

The issues discussed by the Working Group and MDC include the PUB's role with respect to: (1) overseeing the System Operator; (2) performing a market power surveillance and mitigation function; (3) licensing of various market participants, (4) overseeing distribution company rates and the establishment of avoided costs for distribution utilities that have power purchase obligations for embedded generation, and (5) approving new transmission investments. Each of these issues is reviewed below.

The MDC agreed that its proper role with respect to providing guidance on PUB roles and responsibilities generally is to outline the areas of PUB responsibility. However, in a number of areas the MDC believed that it was appropriate to recommend policies to the PUB given the importance of the issue in promoting the MDC's objectives for the New Brunswick market. In addition, the MDC endorsed the *White Paper's* objectives of increasing the administrative efficiency of regulation.

5.1 Oversight of the System Operator

In the Second Interim Report, the MDC made a number of formal recommendations regarding the System Operator that established responsibilities for the PUB. First of all, the PUB was identified as a court of last appeal regarding market rule changes. To carry out these responsibilities the PUB needs authority to serve in this manner and the System Operator must be required to file market rule changes with the PUB. The following two recommendations address these two requirements.

Recommendation 5-50. The MDC recommends that the PUB be given the authority to hear complaints regarding market rules changes upon a complaint filed by a market participant. [3: 4.1]

Recommendation 5-51. The MDC recommends that the System Operator be required to file, for informational purposes, market rule amendments with the PUB.[3: 4.1]

The PUB also needs authority to oversee the independent audit of the System Operator with regards to the application of the market rules and tariffs. It could also require authority to oversee the System Operator's code of conduct and fees. To enable the PUB to fulfill these various responsibilities, the MDC approved the following recommendation.

Recommendation 5-52. The MDC recommends that the PUB be given authority to oversee the System Operator's compliance with the market rules and the tariffs that it administers. This will include the ability to commission an independent audit regarding the System Operator's application of market rules and tariffs. The PUB will approve the System Operator's code of conduct and any fees that may be levied by the System Operator. [3: 4.1]

5.2 Market Power Surveillance

The *White Paper* indicates that "the Province will give the Board the authority to monitor the competitiveness of the wholesale market and ensure that the Crown utility is unable to exercise market power. This role is likely to be in coordination with the Competition Bureau and the System Operator who will have the real-time data necessary to oversee the behaviour of market participants."[15]

There are two distinct, but related, functions to be considered. The System Operator has responsibilities to evaluate the performance of the wholesale market; the PUB has responsibilities for a market power surveillance monitoring function. As indicated in the *White Paper,* the PUB's role with respect to these responsibilities is likely to involve overlap between the System Operator and the Competition Bureau.[16]

The PUB's clear role here is in monitoring for the abuse of market power. In this case, the MDC limited its focus to recommending that the PUB be given that authority. This recommendation is presented below.

Recommendation 5-53. The MDC recommends that the PUB be given authority to monitor for the abuse of market power and take any necessary actions required to prevent or mitigate the abuse of market power. This includes the authority to:

- ***direct the Market Advisory Committee and System Operator to make changes in market rules to address market power abuses;***
- ***impose license conditions;***
- ***issue administrative penalties;***
- ***suspend or revoke a license; and***
- ***advise the Minister regarding necessary structural changes to promote the competitiveness of the market.[3: 4.2]***

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[15] *White Paper*, pg. 28.

[16] A possible model for how these three entities might share these responsibilities is provided by Ontario.

5.3 Licensing

In other markets, licenses have been used as part of the overall regulatory framework to bind licensees to the various Codes, Regulations and Acts that constrain the behavior of market participants. Given that the transmission company will be subject to regulation by the PUB; distributors are publicly owned; and retail competition is limited to large industrial customers, the MDC questioned the need for a formal licensing framework for all market participants. However, a license could provide a useful tool, as for example to discipline generators that are found to be abusing market power.[17] Therefore, the MDC recommended that the PUB should be given the authority to license market participants, to develop, suspend and revoke licenses, and to impose administrative penalties for violations of license conditions.

Rather than offer recommendations as to which market participants should be licensed, the MDC elected to recommend that the PUB be allowed to determine whether such licenses are necessary.

Recommendation 5-54. The MDC recommends that the PUB be given authority to develop, issue, suspend and revoke licenses for market participants where it considers it to be in the public interest. In addition, the MDC recommends that the PUB be given authority to establish administrative penalties for licensees that violate the conditions of their license. In determining whether to require a license the PUB shall consider the nature of the entity and the degree to which they are regulated.[3: 4.3]

5.4 Rate Regulation

Another potential role and responsibility for the PUB is in rate regulation. The MDC considered recommendations on two rate regulation issues: (1) PUB oversight regarding distribution company rates and the charges passed through to end-use customers; and (2) PUB oversight regarding avoided costs that would be paid to generators that are embedded within the distribution system. Each is discussed below.

5.4.1 Regulation of Distribution Company Rates

The *White Paper* provided guidance regarding the PUB's role with respect to the regulation of the distribution utilities. It attempted to balance customer protection interests and concerns with the desire to avoid regulatory oversight that was not warranted. The *White Paper* says:

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[17] The System Operator could prevent the generator from participating in the market. However, this may not possible without imperiling system reliability.

> As a result of allowing the wholesale power price paid by the municipal electric utilities to be determined by the competitive market, there will be no means to assess whether the rates charged to customers are reasonable. In addition, with power purchased in the competitive market, these distribution utilities will be subject to market risks. To address these issues, the Province will require distribution electric utilities to file their rates and all long-term contracts with the PUB. The PUB may initiate an investigation of these rates or long-term contracts based on a complaint from a customer or of its own accord.[18]

The municipal utilities note that they are already subject to a form of regulation under the *Municipalities Act* administered by the Department of Environment and Local Government. The MDC agreed that regulation and oversight by two different provincial agencies is undesirable. However, it felt that after the market reforms, regulation by the PUB may better serve customer protection objectives. The MDC adopted the following recommendation:

Recommendation 5-55. The MDC recommends that the Province undertake to evaluate the appropriateness of the existing form of regulation of electric distribution companies and to make changes if appropriate.[3: 4.4.1]

A second issue the MDC discussed was the role and form of performance-based regulation (PBR) for use by the PUB. The *White Paper* says "the Province will direct the PUB to adopt a light-handed, performance-based method of regulation."[19] How PBR is implemented is not fundamental to the objectives of the MDC. The MDC resolved to recognize that the PUB would establish its own procedures and standards. The Committee decided not to make a formal recommendation on PBR.

5.4.2 Regulation of Avoided Costs

To help eliminate barriers to the development of embedded generation, the MDC recommended that the price paid by distribution utilities for power purchases from embedded generators should be based on the distribution utility's avoided cost. The MDC believes that it is appropriate to have the PUB approve these avoided costs and made the following recommendation.

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[18] *White Paper* pg. 21

[19] *White Paper*, pg. *29*

Recommendation 5-56. The MDC recommends that the PUB be given authority to approve the rates paid by distribution utilities to embedded generators. This shall be based on the avoided costs of the distribution utilities. Avoided costs will be defined by the PUB and can include, but not be limited to, power supply costs, reduced losses and transmission charges.[3: 4.4.2]

5.5 Approving New Transmission Investment

The PUB currently has no legislative authority to review transmission facility applications. The System Operator has the responsibility to cause new transmission to be built for transmission system adequacy and overall system economics. The MDC discussed oversight of the System Operator and the appropriate role of the PUB in overseeing transmission system expansion.

The MDC made no recommendations in this area. It did recognize that if there is a review, it would be appropriate to have a size threshold for the PUB's review of transmission facilities given the costs of a full panel review. Furthermore, the scope of the review is likely to vary depending on the process that is used to determine who builds the facilities.

6 TRANSMISSION ISSUES

The transmission system is central to the operation of any electricity supply system. It is even more crucial to a competitive electricity market, because it is the essential connection between the buyer and the seller. Without open and equal access to the transmission system for all market participants, it is extremely difficult to create a competitive market.

Transmission capacity also affects the size of the market. Without transmission connections, the market would be restricted to New Brunswick alone. With interties, electricity customers in New Brunswick can have access to competitive suppliers from a much wider area.

The level of transmission capacity is an important determinant of the capacity of an electricity supply system to support competitive transactions. The MDC heard that the New Brunswick transmission system is very robust under the current conditions of supply and demand locations, and its configuration can support other modes of operation.

The MDC received and discussed Issues Paper #4: Congestion Management Issues dealing with transmission issues and Issues Paper #12: Transmission Grid Metering dealing with metering issues.

The MDC did not make any recommendations with respect to the overall design of transmission tariffs. Issues with respect to transmission system expansion were dealt with in connection with the roles and responsibilities of the System Operator and the PUB.

6.1 Transmission System Access

The MDC recognizes the importance to the bilateral contract market of open, non-discriminatory access to the transmission system. FERC Order 888 set out what were then (1996) viewed as minimum conditions for open access, including an Open Access Transmission Tariff (OATT). The MDC also recognizes that NB Power is developing a FERC-compatible OATT. The MDC believes that adopting a FERC-compatible OATT will set a minimum standard for open access and clarity in New Brunswick.

Recommendation 6-57. The MDC recommends that the transmission system will provide open, equal non-discriminatory access to all eligible market participants under terms and conditions compatible with FERC Orders 888 and 889. The System Operator will have an Open Access Transmission Tariff (OATT) for network and point-to-point service covering transmission service: within the province, into the province, out of the province, and through the province. The PUB shall approve the OATT.[1: 3.3.4]

The *White Paper* says that the PUB will be given authority to approve transmission tariffs and tolls. The MDC agrees that it should have that authority.

Recommendation 6-58. The MDC recommends that legislation to give the PUB authority to approve transmission tariffs and tolls should be put into place in a timely fashion. [1: 3.3.4].

6.2 Congestion Management

Congestion management issues fall into two related categories: how to handle congestion physically (that is, how to re-dispatch the system to deal with congestion) and how to recover the additional costs congestion imposes on the electricity supply system. The solution adopted for one of these categories can imply or preclude some possible solutions for the other.

The MDC has heard that there is very little transmission congestion within New Brunswick at the present time. However, a competitive market can change the dispatch and stress the transmission system in different ways than when it is under a vertically integrated monopoly.

6.2.1 Physical Congestion Management

By definition, congestion occurs when the transmission system cannot accommodate all the scheduled transactions. That normally implies that cheaper generation cannot be scheduled because it cannot reach load. The result must be some physical re-dispatch of the system, adding more expensive generation and increasing generation costs for the electricity supply system as a whole.

The System Operator will re-dispatch according to some set of rules or protocols agreed in advance. The rules can either be based on a least-cost objective, or they can reflect some pre-stated set of priorities. Whatever rules are used, congestion places additional costs on the electricity supply system. The additional costs must be paid. The models of physical management affect the choice of payment methodology, and vice versa, but they do not determine it uniquely.

6.2.2 Congestion on the Interties

The MDC heard that, although congestion inside New Brunswick is expected to be low, the interties between New Brunswick and neighboring jurisdictions, especially those between New Brunswick and New England, are expected to be congested frequently.

6.2.3 Managing Congestion Financially

The two alternatives for financial management of congestion are to spread the costs among all electricity customers or to link the costs to the locus of congestion. The MDC heard descriptions of methods to accomplish both alternatives. The choice of the bilateral contract market model precluded location based marginal pricing (LBMP), which is one method of linking the cost of congestion to its locus.

Because there is little congestion now, in-province load bears very little congestion costs. If transmission rights are created to manage congestion in the competitive market, existing in-province load would be "grandfathered"; that is, granted rights sufficient to prevent it from paying increased congestion costs.

6.2.4 Congestion Management Model

The MDC considered congestion management approaches and adopted one that resolved many of the congestion management issues in a way that would facilitate a bilateral contract market without creating excessive administrative costs. The approach is contained in the following recommendations.

Recommendation 6-59. The MDC recommends the following resolutions pertaining to the management of transmission congestion inside New Brunswick:

- ***That the System Operator use price and dispatchable capacity information to redispatch the system to mitigate congestion;***
- ***That to enable this redispatch to be performed suppliers with dispatchable capacity be required to provide dispatch up and dispatch down prices and load be able to nominate dispatch up and down prices***;
- ***That a local market power mitigation framework be put in place to limit the exercise of market power for generators that are required to be dispatched up and down;***
- ***That the System Operator settle congestion transactions by***
    - ***Paying for dispatch up energy***
    - ***Billing for dispatch down energy***
    - ***Accumulating net congestion costs[1: 5.1.4].***

Recommendation 6-60. The MDC recommends that the PUB approve a mechanism incorporating the following principles for the recovery of congestion costs:

- ***That congestion costs be allocated to transactions on a load share basis in a timely manner, e.g., monthly;***
- ***That information regarding congestion costs in New Brunswick be collected and made publicly available to enable informed decisions regarding congestion costs to be made;***
- ***That congestion costs within New Brunswick be periodically assessed by the System Operator and reviewed by a stakeholder committee;***

- ***That the System Operator and/or stakeholder committee can recommend modifications to the congestion management mechanism and that such changes should be subject to the approval of the PUB;***
- ***That congestion redispatch cost allocation be allowed to migrate as it becomes material, appropriate and feasible to a congestion management approach that allocates congestion costs to those transactions that cause congestion. In-province loads and existing contracts will receive rights to avoid congestion on pre-existing transmission facilities.[1: 5.1.4]***

Recommendation 6-61. The MDC recommends that management of transmission congestion at interconnections with external systems be done in a manner consistent with FERC principles, as currently described in FERC Order 888.[1: 5.1.4]

6.3 Metering

Metering is fundamental to the settlement of all energy flows and some of the ancillary services. All parties must therefore have a high degree of confidence in its accuracy, reliability, and data integrity.

In the New Brunswick bilateral contract market, more transactions will require billing, which means they will require metering, than under the current regime.

6.3.1 Types of Metering

Metering in New Brunswick was designed to meet the needs of the electricity supply system. It therefore has revenue-quality interval meters for interconnection points and for all large industrial customers. Other connection points generally do not need interval meters.

The table below shows the present deployment of meters in New Brunswick.

	Meter Points	*Interval Meters*	*RQ** CT/PTs*	*MV-90****
Generation	34			
Control Area	12	7	7	7
Large Customers	50	50	50	50
Municipal Loads*	29	1	29	1
NB Power Loads	240	32		
Total	***365***	***90***	***86***	***58***

* Excluding meters on distribution feeders that are not transmission withdrawal points.

** RQ = Revenue Quality. CT = Current Transformer. PT = Potential Transformer. Full definitions in Glossary.

*** MV-90 is computer software that facilitates collection, validation and editing of interval metering data.

After the New Brunswick market is restructured, charge determinants for transmission and ancillary services will change. Also, as recommended for SOS, energy supply will have a more time-of-use orientation. Therefore, the present state of metering may not be adequate.

The MDC discussed possible schedules for upgrading meters. Since major meter upgrades are not required for the basic market, the MDC did not feel that the technical considerations warranted recommending an accelerated upgrade. Also, Recommendation 3-9 says that the System Operator have the authority to set metering requirements.

In light of these considerations, the MDC made the following recommendation.

Recommendation 6-62. The MDC recommends that, consistent with its responsibility to set metering requirements, the System Operator be empowered to determine when new or upgraded meters are required, and instruct the transmission owner(s) to install them.[3: 5.1.1]

6.3.2 Meter Ownership and Meter Service Provision

In some competitive electricity markets, meter ownership and meter service provision are competitive. The MDC did not feel that such an approach would be appropriate in New Brunswick.

Current practice in New Brunswick is that the NB Power Transmission Business Unit owns the meters for connection to wholesale customers. Generators are responsible for the cost of providing meters at their connection points to the transmission system. The MDC decided to continue this practice.

The MDC therefore adopted the following recommendations.

Recommendation 6-63. The MDC recommends that the transmission owner(s) own all meters at injection and withdrawal points from the grid.

- ***Transmission owner(s) will act as "meter data service" provider***
    - ***Maintain meters***
    - ***Responsible for meter data security***
- ***Transmission owner(s) will give the data to the System Operator for use in billing and settlement***
- ***The transmission owners' costs will be included in the transmission tariff.[3: 5.1.2]***

Recommendation 6-64. The MDC recommends that all meters for generation or other injection points to the grid be paid for by the generator.[3: 5.1.2]

6.3.3 Metering Data Control and Confidentiality

Ownership and control of metering data can be a sensitive issue. For many customers, metering data is commercially sensitive. Meter data must be available for billing, including energy, transmission and ancillary services charges, and for use by the System Operator for system planning and for system reliability assessment. To perform these functions, the System Operator[20] needs the meter data. Either the System Operator or the transmission owner may also be subject to data requests from government agencies, including the PUB.

If the transmission owner and the System Operator are both part of a functionally unbundled NB Power Transco, still affiliated with the generation owner, customers will want assurance that their individual metering data will not be transferred, without their permission, between parts of the overall corporation.

NB Power is developing an OATT which will contain a code of conduct governing these aspects of data sharing. This code of conduct should prevent inappropriate data sharing across competitive and non-competitive arms of the company. The MDC therefore adopted the following recommendation.

Recommendation 6-65. The MDC recommends that there be appropriate codes of conduct for the unbundled parts of NB Power:

- ***The Codes of Conduct will be approved by the PUB;***
- ***The Codes of Conduct will prevent inappropriate data sharing; and***
- ***The Codes of Conduct should ensure that NB Power Genco gets no competitive advantage over other competitive suppliers from its affiliation with NB Power Transco and Disco.[3: 5.2]***

In addition to assurance that data will not be inappropriately transferred within NB Power, the customer must have effective control of the use of its individual data. Consistent with this position, and with the understanding that the agencies in possession of the data must make legitimate use of it in addition to their role in billing and settlement, the MDC made the following recommendations.

Recommendation 6-66. The MDC recommends that customers have authority over release of meter data pertaining to their own electricity use:

- ***NB Power Transco can only disclose individual customer's metering data to third parties other than the System Operator with the customer's permission;***

[20] At the start of the market, under the MDC recommendations, the System Operator will be part of the functionally unbundled transmission operation of NB Power. The MDC regards this as a transitional arrangement and therefore, with respect to metering, a distinction is made between the transmission owner and the System Operator.

- ***The System Operator can use the data to fulfill its responsibilities, but cannot disclose individual customer's metering data to third parties other than for billing and settlement purposes;***
- ***NB Power Transco must provide data to prospective suppliers for purpose of preparing proposals, when directed to do so by the customer;***
- ***NB Power Genco should be treated as a prospective supplier to ensure a level playing field; and***
- ***NB Power Transco, Disco and Genco Codes of Conduct will ensure no inappropriate data sharing.[3: 5.2]***

6.4 Charge Determinants for Tariffs and Ancillary Services Charges

The *White Paper* directed the MDC to "review and make recommendations on the role and treatment of small-scale, on-site electricity generation".[21] The MDC's consideration of these issues related both to how transmission and ancillary services would be assessed and to how generators embedded in distribution systems would be treated. This section deals with self-generators generally; section 8.1 of this Report deals with embedded generators.

6.4.1 Charge Determinants for Self-Generators

Self-generation is the production of electricity by the ultimate end user. Self-generation usually occurs on the same site as the use of the electricity. Many self-generation applications are able to utilize both the electricity and the waste heat produced in the electricity generation process. The heat can be used in other process applications. The self-generation is also cogeneration in such applications[22].

Loads pay transmission tariffs and ancillary services charges. However, self-generators have aspects of both load and generation. They are generators when they are selling excess energy; they are loads when they are buying all or part of their requirements. When they are running, connected self-generators can still use services from the grid, both transmission and ancillary services. At issue is the charge determinant for ancillary services and transmission tariffs.

One form of charging is called net load billing. Under it, to the extent that it is meeting its own electricity needs, the self-generator would pay ancillary services charges and transmission tariffs only on its total load net of its own generation.

However, the self-generator is most likely using some ancillary and transmission services from the grid (automatic generation control and reserve backup). An alternative charge determinant therefore is gross load billing. Under it, self-generators would pay for

[21] *White Paper*, pg. 60

[22] Cogeneration is the simultaneous production of electricity and useful heat energy.

ancillary services based on their total peak load, whether or not it was being met by their own generation.

Another dimension to the charge determinant is the time interval over which net load is measured. The longer the time interval, the closer net load billing comes to gross load, because the chances are higher that at some time the self-generation facility will not be running.

The MDC had several discussions on which of these charge determinants to recommend. The advantages of net load billing are that it helps avoid rate shock to self-generators, it is administratively and physically simple (it does not require two meters), and it does not charge self-generators for services when they are not using them. The advantages of gross load billing are that it is consistent with charging customers for the costs they impose on the system, assuming that the use of the ancillary services by self-generators does impose costs.

In its discussion, the Committee noted that using net load billing with a monthly non-coincident peak charge determinant would likely result in total charges close to those of gross load billing if the self-generator is out of service at least once a month for a significant number of months in a given year.

The *White Paper* said that the PUB shall approve charges for ancillary services. Normally, the decision on net vs. gross billing would be made by the regulator after a public process to review the costs, revenues and benefits associated with each method. In this case, the MDC considers it is important to send a strong signal to encourage the expansion of existing self-generation and the development of new self-generation. Therefore, the MDC adopted the following recommendation.

Recommendation 6-67. The MDC recommends that the tariff design approved by the PUB provide that self-generators connected to the transmission system pay for ancillary services on the basis of monthly net non-coincident peak demand.[2: 6.2.3]

The Committee then discussed whether the charge determinant for transmission tariffs should be the same as that for ancillary services. For many of the same reasons as for ancillary services charges, the MDC adopted the following recommendation.

Recommendation 6-68. The MDC recommends that the transmission tariff approved by the PUB provide that self-generators choosing network service will be charged for transmission service on the basis of their monthly net non-coincident peak demand.[2: 6.2.3]

6.4.2 Self-Generator Rate Shock

Recommendations 6-67 and 6-68 represent a significant change from the current treatment of self-generators. Under current practice, self-generators connected to the transmission system do not pay explicitly for either ancillary services or transmission tariffs. Instead, they can contract for interruptible supply from NB Power as a backup.

The reservation price is time-differentiated: $3/MWh. off-peak and $9/MWh. on-peak. If the customers need to use the backup supply, they pay only incremental costs for the energy (not its opportunity, or export, value).

The *White Paper* directed the MDC to look for ways to avoid rate shock for existing self-generators. It also stated that existing and new self-generators should be treated equally, although it implied that avoiding rate shock might require unequal treatment for a phase-in period.[23]

The MDC acknowledged that Recommendations 6-67 and 6-68 could still create a significant rate shock for self-generators. Calculation showed that this rate shock could be as much as $670,000 per year for a typical 20 MW generator. This amount would be mitigated if the self-generator provided ancillary services either to itself or for sale to the grid. Members of the Committee stated that these amounts would constitute a significant rate shock to existing self-generators and a barrier to entry of new ones. For the existing self-generators, they suggested phasing in the transmission and ancillary services charges, as indicated in the *White Paper.*

In discussing this issue, the self-generators noted another problem. They currently buy interruptible supply from NB Power. By the terms of this supply, these customers are not taking backup services; their commitment to NB Power as a condition of receiving interruptible service is that they agree to reduce their load whenever they are notified. Since they are not receiving backup services, it can be argued that they should not be paying for them.

The Committee noted that ancillary services and transmission charges for self-generators is a complex issue. The actual impact on specific self-generators will depend on the kind of service they now receive, on their own operating characteristics, and on the decisions they may take in response to tariff changes. The Committee also noted that these tariff rates would be set in the tariff as constructed and filed by the responsible parties.

To give guidance to that process, the MDC adopted the following recommendation.

Recommendation 6-69. The MDC recommends that the design of the transmission tariff seek to mitigate potential rate shock to self-generators.[3: 5.3]

The Committee expects that the design will consider the suggestions above with respect to phasing in the transmission tariffs and ancillary services charges, and with respect to ancillary service charges for interruptible loads.

[23] *White Paper*, pg. 23

6.4.3 Charge Determinants for Distribution Utilities with Embedded Generation

Generation connected at the distribution level is called embedded generation because it is embedded within a distribution utility. Generators connected at the distribution level cannot be bigger than 5 to 10 MW, given the size of the distribution facilities.

The issue of backup supply and net vs. gross load billing for embedded generation is similar to that for self-generation. The generation owner, and the host utility on its behalf, may look to the grid to provide transmission and backup services.

The alternative charge determinants for embedded generation are the same as those for self-generators: net load billing, gross load billing, or some alternative. The second issue is who benefits from reduced ancillary services charges and transmission tariffs if the charge determinant is less than gross load.

In consideration of additional difficulties associated with embedded generation, and being consistent with the decision with respect to generators connected directly to the transmission system, the MDC adopted the following recommendations.

Recommendation 6-70. The MDC recommends that the transmission tariff approved by the PUB provide that ancillary services charges to distribution utilities be based on monthly net non-coincident peak demand by delivery point.[2: 6.2.4]

Recommendation 6-71. The MDC recommends that the transmission tariff approved by the PUB provide that network service transmission charges to distribution utilities be based on monthly net non-coincident peak demand by delivery point.[2: 6.1.4]

6.5 Unbundling Transmission and Ancillary Services Charges

Customers who are eligible to choose alternative suppliers (contestable) customers have the SOS supply rates as their benchmark cost when they make decisions about alternative supply. To make that decision, the contestable customers will need to be able to separate the electricity supply component of their bills from transmission tariff and ancillary services charges.

Identifying the generation component of the customer bill directly may cause some difficulty, given the potentially mixed sources of the supply (SOS and market-based). The Committee noted that it would be sufficient to identify the regulated and unavoidable parts of the customer bill; the cost of supply could then be identified by subtraction.

To allow contestable customers to compare alternatives more easily, therefore, the MDC made the following recommendation.

Recommendation 6-72. The MDC recommends that bills to contestable customers separately identify the cost of transmission and ancillary services.[3: 2.1.5]

7 MARKET POWER ISSUES

7.1 Introduction

As a Crown utility with an obligation to serve, NB Power controls essentially all of the capacity in the New Brunswick power market, either through outright ownership or under long-term contract. The major sources of competitive power are New Brunswick's interties with Quebec, New England, and Nova Scotia. Consequently, NB Power's potential market power is a major issue.

Recognizing the challenge posed by ensuring a workably competitive wholesale power market, in the *White Paper* the Province directed the Market Design Committee to make recommendations for the mitigation of market power in the wholesale and large industrial retail electricity market such that the target implementation date can be achieved.

The MDC received and discussed a presentation on market power. Items discussed included definition and recognition of the presence of market power, and criteria for assessing the competitiveness of wholesale markets.

7.1.1 Defining Market Power

Market power is defined as the ability of a seller, or group of sellers acting in concert, to profitably maintain prices above competitive levels for a significant period of time.[24] Note that the focus is on the profitability of the price increase and the degree to which the price increase results in a significant increase in profits. The phrase "for a significant period of time" recognizes that if the price increase is transitory because competition quickly forces prices down, or and only for a relatively few hours of the year, then this increase in prices is not likely to enhance significantly the firm's profitability. In sum, when evaluating whether a firm is likely to possess market power one should evaluate the magnitude of the price increase and the period over which the price increase occurs.

Market power is of concern because it can, if exercised, impose costs on society. The exploitation of market power can significantly erode the consumer benefits that would be expected to result from the transition from regulated to competitive markets for electricity generation.

There are two general forms of market power: vertical and horizontal. Vertical market power can arise from the ownership or control of more than a single step in the production and delivery of a particular product. Vertical market power can be exercised to limit entry and to provide preferential treatment for affiliates. Horizontal market power can arise if a single entity or small group of entities owns or controls most of the

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24 U.S. Department of Justice (DOJ) and Federal Trade Commission (FTC), *Horizontal Merger Guidelines*, April 2, 1992.

productive resources at a particular level of production. Horizontal market power can be exploited to raise prices or create or maintain barriers to entry.

Given NB Power's position as vertically integrated utility serving the vast majority of New Brunswick, both forms of market power are of concern to the MDC.

7.1.2 Identifying the Presence of Market Power

Structural assessment of a market looks at the number and relative sizes of sellers. Recognizing that it is a screening device which should only be used as an indicator of the possible presence of market power, market share tests are commonly applied by various regulatory agencies.

The first step in evaluating the likely competitiveness of a market is to define the relevant market. There are two dimensions to defining a market. The first is the relevant product market. The second dimension is to define the market's geographic scope.

In the market being developed by the MDC, with ancillary services procured under contract by the System Operator, the relevant product market is electrical energy. The scope of the relevant New Brunswick geographic market is defined in terms of the locations of the various generators that can physically and economically access the market.

7.1.3 MDC Resolution on NB Power Activities

The MDC noted that the contestable market might offer too few contracting opportunities to attract competitive suppliers. The MDC also saw a possibility that, at market opening, NB Power would have so much of the potentially contestable market already tied up under long-term contracts as to forestall entry.

The MDC further expressed concern that NB Power might aggressively seek new contracts during the period leading up to market opening. It therefore passed a resolution indicating to the Minister its desire for maximum possible participation in the bilateral contract market, and its desire to constrain the behavior of New Brunswick Power.

Resolution 2. The MDC believes that there should be appropriate mechanisms to maximize the opportunity for wholesale and large industrial electricity customers to participate in the market at the time of market opening.

Furthermore, appropriate mechanisms should be in place to ensure that New Brunswick Power's behavior during the transition to market opening not impede effective operation of the electricity market after market opening.

7.2 Market Power Mitigation in the Bilateral Contract Market

Several issues with respect to mitigating market power could not be resolved until the MDC completed its decisions on SOS supply. These decisions were critical to framing the market power mitigation requirements because NB Power Genco's SOS obligations represent a Vesting Contract. Committing NB Power Genco to provide the capacity and energy offered by the heritage assets for SOS reduces the need for additional market power mitigation strategies.

A number of elements of the market design being recommended by the MDC limit the potential for the abuse of market power. These include: (1) bilateral contract market; (2) regulated ancillary services and (3) regulated SOS service.

Bilateral contract markets are less susceptible to market power abuse than real time markets because pricing decisions are made over significantly longer time frames. In a real time market where demand and supply are matched on an hourly basis, any supplier with resources that are required to satisfy demand at any given time has the ability to influence prices.

7.3 Regulated Ancillary Services

The second element of the New Brunswick market design recommended by the MDC that serves to mitigate the exercise of market power is that ancillary service costs will regulated by the PUB, as specified in Recommendation 3-31.

Among the most important ancillary services for a generator in a bilateral contract market is balancing service to cover differences between scheduled and actual injections and withdrawals. Given the limited size of the New Brunswick market, prospective generators could be reluctant to participate if they believe that they could be exposed to significant risks as a result of uncompetitive imbalance charges.[25]

In Recommendation 3-30, the MDC recommended that balancing service be provided through the transmission tariff with price ceilings and floors as necessary to protect participants. This final provision should provide the protection necessary to ensure that the pricing for balancing service does not become a barrier to entry for competitive suppliers.

7.4 Regulated SOS Service

In the Second Interim Report, the MDC recommended that SOS be offered at rates based on the SOS supplier's blended cost of providing this service. Therefore, if customers are allowed to return, SOS can represent a "safe harbor" from attempted market power

[25]Imbalance service is provided as an ancillary service under NB Power's transmission tariff. NB Power's existing imbalance charges are based on the FERC pro forma tariff and price imbalance service as a penalty.

abuses in the retail market. The MDC's discussions and recommendations regarding this issue are discussed in Section 4.5 of this report.

Recognizing that a return right to SOS can be an effective market power mitigation strategy and reduces the perceived risks to customers of moving to the competitive market, and balancing against the possibility of shifting costs to other market participants, the MDC made the recommendations shown in Section 4.5.

7.4.1 Minimizing Barriers to Entry

If the objective is to promote the development of a competitive wholesale market in the long run the focus should be on minimizing undue barriers to entry. One requirement is that project developers be assured they can adequately manage development and operating risks.

One operating risk is ensuring that the generator can obtain access to a competitively priced supply to fulfill contract commitments when they are unable to do so. In the market as designed, market participants can split between competitive supply and SOS supply, and move towards SOS if the competitive supplier is unavailable. This provision carries some potential for abuse by competitive generators. There may be a need to establish performance criteria to limit a supplier's ability to have its customer be backstopped by the SOS supplier or to ensure that this backup service is only utilized when the competitive supplier's generating resources are unavailable.[26] These issues will need to be further considered in the market rules development process and by the SOS supplier in designing the terms and conditions for SOS. To make clear that an important element of SOS is backup service, the MDC made the following recommendation.

Recommendation 7-73. The MDC recommends that, until there is workable competition, the SOS supplier be required to provide back-up service regulated by the PUB. [3: 3.3]

7.4.2 Equal Opportunities to Provide SOS

Recommendations 4-46 and 4-47 help ensure prospective suppliers that the procurement process for SOS supply will be overseen by the regulator with a view towards making it fair and transparent. Recommendation 4-49 assures prospective suppliers that they can

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[26] It is inappropriate to require the SOS service provider to provide backup service to a customer so that a competitive supplier can take advantage of more attractive market opportunities. Furthermore, for traders and marketers that are not necessarily supplying a customer from a specific generating resources it would be essentially impossible to tie access to this backstop service to generator performance criteria.

offer to the SOS supplier at any time. Because the SOS supplier may be affiliated with NB Power Genco who will have the contractual commitment to provide supply from the Heritage Pool, it is important that prospective suppliers be confident that they have such an equal opportunity to compete to supply the SOS supplier.

One way to remove any possible bias by the SOS supplier towards its generation affiliate would be to prohibit NB Power Genco from responding to RFPs. This would also limit its degree of control of generation assets in New Brunswick. However, Recommendation 4-48 specifically enjoins NB Power Genco to respond to any RFP from the SOS supplier.

The final issue that the MDC discussed pertained to ensuring a level playing field between NB Power Genco and competitors. In particular, competitors to NB Power Genco could have a competitive advantage in using existing sites, where it can leverage off of the existing infrastructure, e.g., transmission facilities, cooling water, plant staffing and controls.

To level the playing field it was proposed that NB Power Genco be required to "pay" for this benefit, by essentially making an offsetting payment for these benefits to SOS customers. This would ensure that NB Power's bids reflect the full costs of building the new project. Paying this credit to existing customers would ensure that they obtain that benefit. It could also impose costs, if it raises a potentially winning NB Power Genco bid. However, there is no requirement that NB Power submit a cost-based bid and therefore, no way to ensure that NB Power would share the savings represented by these infrastructure benefits with customers. Mandating that NB Power Genco pay for these infrastructure benefits would ensure that SOS customers are compensated for this value and prevents NB Power from extracting this value. The MDC elected to make no recommendations on this issue.

8 ENVIRONMENT AND RENEWABLES

A major goal of the New Brunswick Energy Policy is to *protect and enhance the environment.* To this end, the *White Paper* addresses such policies as green pricing, development of a provincial Climate Change Action Plan, promotion of alternative energy innovation and a commitment to long-term environmental sustainability.

Identification and evaluation of policies to improve environmental protection and enhancement in the electric industry is both facilitated and complicated by restructuring. Electricity market restructuring brings new rules, organizations, and strategies. Environmental considerations must be an important part of electricity restructuring. Restructuring can potentially contribute to achieving environmental policy objectives.

Total economic costs of low-impact technologies may be lower than those of conventional technology when environmental damage costs are considered.

The Market Design Committee had two basic modes of action with respect to environmental protection and enhancement.

The first was to ensure that its recommended market design and associated rules are consistent with policies for environmental protection and enhancement. The second was to explore ways to encourage the adoption of renewable and lower impact technologies. Consistent with this approach, the MDC included environmental protection and enhancement in the criteria it used to evaluate policy choices.

Discussion of encouraging lower impact technologies began with Issues Paper #9: Alternative Energy and Environmental Concerns. Issues Paper #8: Self Generation, Small Generation, and Embedded Generation Issues addressed issues of small, embedded and self generation, some of which are included in this section. The Committee formed an Environmental Issues Working Group. The Working Group produced recommendations and clarifications on proposed policies: eligibility for net metering, further definition of a renewable portfolio standard (RPS), further definition of a systems benefit charge (SBC) to promote energy efficiency, and promotion of cogeneration.

During its discussions, the MDC broadened its scope to add issues of promotion of energy efficiency in more general terms, discussion of green pricing programs,[27] emissions trading, and emission performance standards.

The MDC approved an overall recommendation addressing all of these issues.

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[27] The *White Paper* said that the province would direct the distribution utilities to offer green pricing programs.

Recommendation 8-74. The MDC recommends that the Province implement the following programs in order to meet its goals for environmental protection and enhancement in an economically efficient manner:

- ***Net metering and support for embedded generation;***
- ***Renewable portfolio standards;***
- ***Energy efficiency programs;***
- ***Green pricing;***
- ***Broad-based CO_2 emissions trading;***
- ***Emission performance standards; and***
- ***Promoting cogeneration.[3: 6]***

This section will deal with all of these recommendation areas.

8.1 Net Metering and Support for Embedded Generation

The *White Paper* said the MDC should review and make recommendations on the role and treatment of small-scale, on-site electricity generation.

8.1.1 Net Metering

If an on-site generator is installed on the customer side of the meter and services only the load at its site, the generation does not need to be priced in the market. The customer implicitly gets the full retail price for the electricity generated on-site.

On-site generators may on occasion have excess power to sell. The cheapest and easiest way to accept and price generation from such small sources is to use net metering. Under net metering, the revenue meter effectively runs backwards whenever the on-site generation is producing more electricity than the load is using.

This approach prices all of the electricity generated on site at the full retail cost. This may overprice such generation. However, in many jurisdictions net metering is seen as a way of encouraging small-scale generation. Often, such generation uses intermittent technologies like wind or solar sources, which are desirable on environmental grounds.

Because net metering is seen as preferential treatment, many jurisdictions restrict the maximum size of the generator or the maximum amount of generation eligible for net metering. The MDC's recommendation on net metering is consistent with these principles. In addition, some members were concerned with the potential for large amounts of net injections into the system from net metering to impose costs on both the distribution and generation systems.

In keeping with these concerns, and with the desire to promote small renewable generation and cogeneration, the MDC adopted the following recommendation.

Recommendation 8-75. The MDC recommends that distribution utilities must allow embedded renewable generators or cogenerators with capacity of 100 kW or less per metering point to use net metering. Each distribution utility shall establish an amount of kW as a cap for the aggregate capacity of net metering projects within its territory. A suggested cap is 1% of the 5-year average maximum demand of the distribution utility.

Net metered customers will have the choice of:

- ***Monthly bill and payment cycle, with net injections over the month paid at the host utility's avoided cost; or***
- ***Carryover of net injections which can offset net withdrawals in future months. At the end of each calendar year any net injections will be zeroed out without compensation to the generators. [2: 6.2.6]***

8.1.2 Physical Support for Embedded Generation

Embedded generators, by definition, connect to the electricity supply system through the distributor. To meet its own requirements for system reliability and safety, the distributor must set physical standards for the connection. Meeting reasonable technical standards for connections is one of the costs of doing business for any generator, including embedded generators.

In order to facilitate investment in this area, it is necessary to minimize costs and increase certainty through the use of non-discriminatory standards. The MDC made the following recommendation.

Recommendation 8-76. The MDC recommends that distribution utilities be required to adopt an appropriate common interconnection standard which does not discriminate against embedded generation. [2: 6.2.4]

8.1.3 Market Support for Embedded Generation

Self-generators may at times have excess power available to sell to other electricity users. Recommendation 3-4 says that such generators should be eligible to sell in the bilateral contract market. Another potential buyer is the host utility itself.

It will be administratively easier for embedded generators simply to sell to the host utility than to participate directly in the bilateral contract market. The MDC discussed whether the host utility should have an obligation to buy power from embedded generators, and if so at what price. Having the host utility buy power from the embedded generators at a price equal to their avoided cost would present a defined opportunity to the embedded generator at no or low cost to the host. The MDC therefore adopted the following recommendation.

Recommendation 8-77. The MDC recommends that the host utility be required to purchase electricity under contract from embedded generators at a price equal to its avoided cost.[2: 6.2.5]

8.2 Renewable Portfolio Standard

A Renewable Portfolio Standard (RPS) requires that a certain percentage of annual electric consumption come from renewable energy. The *White Paper* commits the government to monitoring the benefits of RPS in other jurisdictions and assessing its benefits for New Brunswick.[28] The general framework contains a requirement that a minimum portion of usage (typically as a percentage of energy use) be from renewable sources. The minimum requirement typically starts with some base level and escalates over time, to ensure that the share of renewables grows. The RPS can also specify the type of alternative energies that meet the RPS requirements.

Implementing an RPS raises several important issues. These include setting a base level, setting an initial target and its rate of increase, defining eligible generation, and determining how the requirement can be met.

The MDC considered all of these issues and agreed that New Brunswick should adopt an RPS. The RPS discussions led to an understanding of principles for the development of an RPS. The MDC, therefore, approved the following recommendations.

Recommendation 8-78. The MDC recommends that the Province implement a Renewable Portfolio Standard (RPS) in order to help meet the goal of environmental protection and enhancement and achieve the White Paper's objective to foster the development of renewable energy resources.[3: 6.1]

Recommendation 8-79. The MDC recommends that the Renewable Portfolio Standard (RPS) be based on the following principles:

- ***An RPS is a tool that should be implemented by the government in order to help meet its environmental protection and enhancement goals without creating undue upward pressure on rates;***
- ***An RPS should be based on a percentage of total customer electricity use;***
- ***The RPS requirement should be placed on loads;***
- ***Customers who choose a competitive supplier or self-supply must demonstrate that they meet the RPS requirement;***
- ***The SOS supplier shall meet the RPS requirement on behalf of all remaining customers;***

[28] *White Paper*, pg. 61.

- ***The percentage should gradually increase over time, in a way that is determined in advance, to provide certainty to developers of renewables. In setting this percentage increase due consideration should be given to the expected requirement for new generation resources;***
- ***Existing renewables would be the floor above which the RPS requirement for new projects is set. RPS energy can only come from:***
  - ***New renewable projects***
  - ***Incremental capability from existing renewable facilities***
  - ***Refurbishment of existing renewable facilities in lieu of retirement. [3: 6.1]***

The RPS target can be higher if renewable resources outside New Brunswick qualify. To qualify, they should come from jurisdictions with a reciprocal program. The RPS should be achievable using a system of trading credits for qualifying renewable generation. The system should, where possible, be compatible with those of neighboring jurisdictions with which credits might be traded.

8.3 Energy Efficiency Programs

The *White Paper* proposed a comprehensive energy efficiency strategy. Included in that strategy was a commitment to "seek a variety of broad-based energy efficiency funding mechanisms."[29] The MDC considered approaches to promoting energy efficiency, including funding mechanisms.

In markets where generation is not regulated, one funding approach for energy efficiency programs is a systems benefit charge (SBC) or similar mechanism.[30] An SBC is a charge placed on all electricity users.

While the MDC supported promoting energy efficiency, it did not recommend an SBC. Because an SBC can be used for such a wide variety of purposes, the MDC felt that any recommendation it made would require careful thought about the purposes of the fund and about the mechanisms for its use.

During its discussions on an SBC, the Working Group drew on its own experience and on its knowledge of programs in other jurisdictions to enunciate some principles for energy efficiency programs, which it recommended that the Committee put forward.

The MDC recognizes that the Province is committed to the development of energy efficiency programs. The MDC adopted the following recommendation in light of that recognition.

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[29] *White Paper*, pg. 52.

[30] The term SBC is used to represent any charge on electricity for social purposes. Such charges have different names in different jurisdictions.

Recommendation 8-80. The MDC recommends the following principles be used in designing energy efficiency programs:

- ***The energy efficiency programs should have dedicated program funding;***
- ***Energy efficiency programs need a central facilitator separate from energy suppliers;***
- ***Energy efficiency programs should be designed based on following best (and avoiding worst) practice; and***
- ***New energy efficiency programs should complement, but not duplicate existing programs. [3: 6.2]***

8.4 Green Pricing

Green pricing programs offer electricity consumers the choice of paying more to fund electricity from new renewable or other low impact sources. In general, such resources are more expensive in money terms than are conventional sources, but some consumers are willing to pay more for such electricity.

The *White Paper* said that the government would require all distribution utilities to offer green pricing programs. NB Power told the MDC that it is developing a green pricing program. Once the program is developed, it will offer other distribution utilities in the province the opportunity to participate in it.

Implementing green pricing raises several of the same issues as the RPS does. The MDC recognized that the Province is committed to the development of green pricing, and adopted the following recommendation.

Recommendation 8-81. The MDC recommends that green pricing programs be based on the following principles:

- ***Energy from renewable sources that receive an RPS credit cannot be offered as green power; and***
- ***Green power be defined according to a widely accepted definition, such as the EcoLogo definition . [3: 6.3]***

8.5 Emissions Trading

The MDC recognized in its discussions that implementing policies on renewables, small generation, energy efficiency, and cogeneration would reduce generation from high-impact fossil sources, but would not eliminate it. The MDC considered policies to ensure better environmental performance from the existing resources: broad-based emissions caps and trading systems, and emissions performance standards.

The MDC recognized the commitment of the government to policies to deal with climate change issues; the *White Paper* said that the province will produce a provincial Climate Change Action Plan.[31] The Committee expects that the government would welcome comments from the Committee on ways to achieve its climate change goals.

The MDC acknowledged the Province's consideration of cap and trade programs for all air emissions. The MDC adopted this recommendation with respect to emissions caps and trade for greenhouse gases.

Recommendation 8-82. The MDC recommends that the Province, in negotiation with the federal government and the New England Governors and Eastern Canadian Premiers, pursue the inclusion of emissions trading as part of the Climate Change Action Plan.

The MDC recommends that an emission trading system be based on the following principles:

- ***Tradeable permits be for CO_2 and other greenhouse gases converted to CO_2 equivalent emissions;***
- ***The system be geographically broad based;***
- ***Compliance be certified through a registry; and***
- ***The system should be based on a cap which should decline over time.[3: 6.4]***

8.6 Emission Performance Standards

Performance standards reinforce an emissions trading system. Such standards can require generators either to meet a fixed performance standard or to buy credits from those whose performance is better than the standard.

The MDC acknowledges that emission performance standards for electricity generation could help to reduce emissions.

The MDC adopted the following recommendation.

Recommendation 8-83. The MDC recommends that the Province consider the application of emission performance standards as part of its Climate Change Action Plan. Compliance with such standards could be a requirement for electricity sales into New Brunswick and/or as a means of allocating caps under a regional or national trading market. [3: 6.5]

[31] *White Paper*, pg. 63.

8.7 Promoting Cogeneration

The *White Paper* commits the province to "promote cogeneration as the most energy efficient electricity generation option."[32] The MDC agrees that cogeneration is an attractive energy efficient option. In designing the market, the MDC has considered the potential impact of its recommendations on cogeneration opportunities.

The MDC supports the development of additional cogeneration in New Brunswick given its favourable environmental attributes. The MDC therefore adopted the following recommendation.

Recommendation 8-84. The MDC recommends that the Province establish a multi-stakeholder group to identify barriers to the development of cogeneration in New Brunswick and recommend specific policies to encourage cogeneration. The group should consider such things as:

- ***Preferential treatment of cogeneration to meet new supply requirements;***
- ***Reduced (or no) exit fees for cogeneration projects;***
- ***Credits to cogeneration projects for reduced environmental impacts;***
- ***A cogeneration portfolio standard; and***
- ***Differential treatment based on heat rates, size, fuel, etc.[3: 6.6]***

[32] *White Paper*, pg. 54.

9 TRANSITION ISSUES

9.1 Stranded Costs and Exit Fees

Costs that were incurred by utilities in connection with the provision of their regulated monopoly service and that cannot be recovered in a competitive marketplace are stranded. Stranded costs arise in a competitive market when the costs of such plants or assets are so high that, given the competitive choice, consumers no longer buy their output.

The recovery of legitimate stranded costs is necessary to prevent cost shifting among customer classes and to treat utility investors fairly.

Three key sections in the *White Paper* addressed the issue of stranded costs and cost shifting. In discussing the implementation of wholesale competition, the *White Paper* said “the Province will require wholesale participants that reduce their firm load on the Crown utility’s system to levels that are below their calendar year 1999 load, to be assessed an exit fee or other equivalent charge, approved by the Board.”[33] In relation to industrial customers, the *White Paper* stated “development of self-generation projects could create stranded costs in New Brunswick due to displaced sales from the Crown utility combined with transmission limitations to New England.” Therefore, “the Province will require self-generators that reduce their firm load on the Crown utility’s system to levels that are below their calendar year 1999 load to be assessed an exit fee or other equivalent charge.” Along similar lines, the *White Paper* also stated that “the Province will require large industrial customers that reduce their firm load on the Crown utility system to levels that are below their calendar year 1999 load, to be assessed an exit fee or other equivalent charge.”[34]

The issue of stranded costs raises a number of questions. These include the exact definition of stranded costs, the calculation methodology used to determine the magnitude of these costs, methods to mitigate these costs, and cost-recovery mechanisms to be used (*e.g.,* exit fees). The MDC received Issues Paper #10: Stranded Costs and Exit Fees on this topic.

9.1.1 Definition of Stranded Costs

In general, stranded costs can be defined as the difference between the market and book values of a utility’s assets. Stranded costs should not include losses associated with

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[33] *White Paper*, pg. 18.

[34] *White Paper*, pg. 22-3 and 25.

normal business conditions or other risks that utilities routinely face under traditional regulation. This includes changes in load growth and the introduction of new technology.

Legitimate stranded costs are those costs that cannot be mitigated, or offset, by the utility. Stranded cost mitigation techniques could include reduction of expenses; renegotiation of power purchase and fuel-supply contracts; refinancing of existing debt; and the maximization of market revenues from existing generation assets.

In the New Brunswick market, contestable customers can create stranded costs either by self-generation or by turning to alternate suppliers. Since most customers will not have a choice of electricity suppliers, they cannot create any stranded costs and it can be argued that they should not have to pay costs stranded by others. The focus for the stranded cost recovery is on the market participants who create it.

The MDC also considered the question of whether a customer who reduces demand on the system could create a benefit, but decided that stranded benefits would not be paid out, although the view of some members was that benefits should be recognized.

These decisions are implemented in the following recommendation.

Recommendation 9-85. The MDC recommends that, as a general principle, the cost of an exiting SOS customer that would otherwise be imposed on remaining SOS customers should be assigned directly to that customer.[3: 7.1.1]

The MDC made clear that stranded costs could only be created by a deliberate action, such as increasing self-generation or moving to a competitive supplier, which reduced load on the system.

Because the customers would have been buying interruptible load, any exit fees related to loads supplied by self generation existing in 1999 would be based on the net value of load presented to the system and not the gross value of installed load.

This recommendation defines which actions can create stranded costs.

Recommendation 9-86. The MDC recommends that a contestable customer be assumed to create stranded costs only when it takes a deliberate action to reduce its firm load through the procurement of competitive supply or the development of a self-generation project. [3: 7.1.1]

The MDC has recommended that contestable customers can take all or any part of their supply from the SOS supplier or from the competitive market. To ensure that taking partial supply from the competitive market did not exempt a customer from responsibility for stranded cost payments, the MDC adopted the following recommendation.

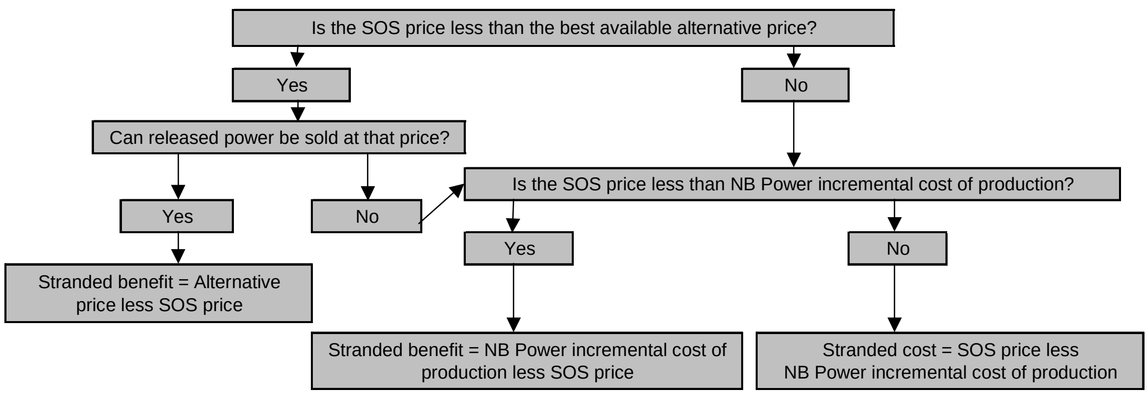
Recommendation 9-87. The MDC recommends that a contestable customer that leaves SOS for a portion of its load would be viewed as potentially creating stranded costs for that portion of its load that would no longer be served by SOS.[3: 7.1.1]

9.1.2 Valuation Methodologies

Utilities and regulators use a variety of approaches to calculate stranded costs. All approaches compare the regulated values of utility assets and liabilities with their competitive-market values.

The question of whether New Brunswick will experience generation-related stranded costs or stranded benefits hinges on the relationship between the (SOS) price, NB Power Genco's incremental cost of production, and the New England export market price.[35] These relationships are shown in Figure 2.

Figure 2
Stranded Cost Determination



The Committee concluded that stranded costs could be incurred relative to any firm load and to the assets used to supply that load. Over time, the SOS supplier will be obliged to contract for supply above the Vesting Contract amount. Since that supply is for customers who cannot or choose not to switch suppliers, these new amounts could also be considered a potential source of stranded costs.

Recommendation 9-88. The MDC recommends that stranded cost recovery be based on costs of all resources to meet SOS supply obligations. Such costs would include the Vesting Contract and contracts prudently entered by the SOS supplier.[3: 7.1.2]

Making the SOS customers liable for stranded costs for all their SOS supply could expose them to having to pay for imprudent decisions of the SOS supplier. The PUB is an appropriate body to oversee the contracting practices of the SOS supplier.

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[35] This assumes that the departing customer was receiving standard offer service.

Recommendation 9-89. The MDC recommends that supply contracts entered into (after an RFP process) by the SOS supplier for amounts above the Vesting Contract amounts be one of the elements subject to review in the rate setting process for the SOS supplier.[3: 7.1.2]

Recommendation 9-90. The MDC recommends that stranded cost recovery be based on the firm load of the exiting contestable customer at the time of notification of exit.[3: 7.1.2]

The recommendations above effectively prevent any cost shifting by contestable customers, when they leave SOS supply. The basis for stranded cost calculations will be whatever level of supply is contracted. Any costs the SOS supplier incurs to provide that supply could be subject to stranding if the customer chooses to leave at any time.

These recommendations are inconsistent with the *White Paper's* statements that exit fees will be assessed only relative to a 1999 base load.[36] The MDC made this decision in light of its extensive discussions of the problems potentially created by customers who can freely leave from and return to SOS supply, and the potential inequities in the treatment of new loads accessing the system after 1999.

The MDC acknowledges that the calculation of stranded cost would take into account the changing conditions of supply and demand in the New Brunswick market. At the point when the SOS supplier is required to issue an RFP for new supply, it can be expected that there would be no stranded cost.

Recommendation 9-91. The MDC recommends that whenever an RFP is required for SOS supply, exiting load should be considered as part of the possible supply, and exit fees, if any, could be waived.[3: 7.1.2]

9.1.3 Cost-Recovery Mechanisms

Once net qualifying stranded costs that are recoverable from customers are determined, one or more mechanisms for assessing those costs on the appropriate parties must be implemented. The *White Paper* specifically mentioned an exit fee or other equivalent charge. Exit fees require departing customers to pay the utility for the stranded costs associated with those customers' decisions to select a competitive supplier or to self-generate their energy needs. The *White Paper* also indicated that stranded cost recovery would be regulated by the PUB.

The MDC agreed that the PUB is the appropriate body to administer the assessment of stranded costs.

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[36] *White Paper*, pg. 18 (wholesale customers), pg. 23 (self-generators), pg. 25 (industrial customers).

Recommendation 9-92. The MDC recommends that the PUB be given authority:

- ***To determine stranded costs and set exit fees; and***
- ***To review and adjust them as appropriate.[3: 7.1.3]***

The MDC discussed several possible mechanisms for calculation of stranded costs, but recognized that the PUB would ultimately have authority.

The recommendation below provides certainty on stranded costs for potential customers for competitive supply.

Recommendation 9-93. The MDC recommends that the stranded cost methodology reflect the following principles and practices:

- ***Exit fee(s) should not unduly discourage competitive supply choices;***
- ***The exit fee/stranded cost calculations should be transparent so that customers can evaluate their likely costs;***
- ***To provide transparency and some measure of certainty a stranded cost should be established for customer migration up to a specific level; and***
- ***The customer should have the right to an explicit calculation of its exit fees at the customer's expense.[3: 7.1.3]***

9.2 Market Rules

The Market Design Committee has made recommendations on the nature and function of the electricity market in New Brunswick. Most of these recommendations are necessarily at a high level of abstraction. To implement them requires a more detailed set of rules for the operation of the market. These are called the market rules.

Market rules are crucial determinants of market function, as experience in other markets has consistently demonstrated. In general, changes in the market rules favor some market participants relative to others.

Setting up a process for changes in the market rules therefore requires balancing the need for flexibility to deal with problems as they arise against the need to have stable rules to give potential investors and other market participants confidence in the stability of the market.

The System Operator governance structure and the process for changing the market rules are contained in Recommendations 3-17 to 3-19.

For the transition to that structure, the MDC considered the issues of responsibility for the initial development of market rules and principles for their development.

To create the first market rules, the MDC decided to rely on the Minister. Once the Minister produces an initial draft, the Market Advisory Committee (which is the multi-stakeholder body recommended to have responsibility for recommending changes in the market rules) will review them and recommend necessary changes to the Minister. The Minister will have final approval of the initial market rules. [37]

To implement these decisions, the MDC approved the following recommendation.

Recommendation 9-94. The MDC recommends that the Minister develop a draft of the market rules, the Market Advisory Committee review and revise this draft as necessary and be charged with final responsibility of developing the initial market rules that will be submitted to the Minister for approval.[3: 7.2]

As further guidance in writing the initial market rules, the MDC decided to adopt principles for the rules. The Committee has adopted principles for its decision making which it felt would be entirely appropriate to guide the market rules. In addition, the purpose of creating the market rules should be to implement the recommendations of the MDC.

The MDC therefore adopted the following recommendation.

Recommendation 9-95. The MDC recommends that the objectives used to guide the market rule development be:

- ***To implement the recommendations made by the MDC; and***
- ***To promote the following principles (as further outlined in The Criteria for Decisions of the MDC):***
    - ***Economic efficiency and the efficient allocation of risk;***
    - ***Reliability of the system;***
    - ***Transparency;***
    - ***Fairness;***
    - ***Robustness;***
    - ***Enforceability;***
    - ***Environmental protection and enhancement; and***
    - ***Protection of non-contestable customers. [3:7.2]***

[37] In Phase 2, the Committee recommended that the System Operator have the power to change market rules, upon advice from the Market Advisory Committee. Any market participant has the right to appeal changes, first to the System Operator and then to the PUB.