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DAVID WILLIAMS

O'DEA, EARLE LAW OFFICES

323 Duckworth Street
P.O. Box 5955
St. John's, NL
Canada A1C 5X4

Telephone 709 726 3524
Facsimile 709 726 9600

odeaearle@odeaearle.nf.ca
www.odeaearle.nf.ca

January 19, 2007

Via Courier

Ms. G. Cheryl Blundon
Director of Corporate Services and Board Secretary
Board of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

Dear Ms. Blundon:

Re: 2006 Newfoundland and Labrador Hydro General Rate Application

This correspondence is delivered and filed pursuant to the Board's Procedural Order [P.U. 28 (2006)] and in particular paragraph 13 (i) thereof which states:

"13. (i) **A party wishing to examine or cross-examine a witness on a document that is not:**

a. **Already part of the record of the proceeding:**
b. **A portion of a transcript of the witness' own testimony given within the preceding two (2) years or in NLH's last two (2) General Rate Applications, or**
c. **An Order of the Board,**

shall:

i **file a copy of the document with the Board and all parties by 3 p.m. on the last business day before the examination or cross-examination is to take place;**
ii **provide ten (10) copies to the Board Secretary on**

the day of the examination or cross-examination; and

iii **give the witness a reasonable time to review the document before the witness is asked to answer any question concerning the document."**

In relation to the cross-examination of Mr. James Haynes we file ten (10) copies of the following:

1. Article from The McKinsey Quarterly: The Online Journal of McKinsey & Co. by Hunter, Melnick and Senni (2003) entitled, "What Power Consumers Want";

2. Article from Platts Electric Utility Week (August 4, 2003) p. 19 entitled "McKinsey sees utilities overspending on reliability more than customers care";

3. June 2004 report entitled "A Compendium of Electric Reliability Frameworks, Across Canada produced by the National Energy Board;

4. Peer Group Performance Measures for Newfoundland Power dated December 21, 2006.

Copies will be provided to all other parties this afternoon.

Yours very truly,

O'DEA, EARLE

THOMAS JOHNSON
TJ/cel
encl.

cc: Newfoundland and Labrador Hydro
Attention: Ms. Gillian Butler, Q.C. info@gillianbutler.com
and Geoffrey P. Young gyoung@nlh.nl.ca

Newfoundland Power
Attention: Mr. Ian Kelly, Q.C.
and Mr. Peter Alteen palteen@newfoundlandpower.com

Industrial Customers
Attention: Paul L. Coxworthy pcoxworthy@smss.com
and Joseph S. Hutchings jhutchings@pa-law.ca

Member Edition | 8 August 2006

Energy, Resources, Materials: **Electric Power**

Tools

Research in Brief

What power consumers want

Most customers are satisfied with the reliability of their electric service. So why are power distributors still making huge infrastructure investments?

Richard Hunter, Ronen Melnik, and Leonardo Senni

2003 Number 3

Few would question the wisdom of electric-power distributors that invest in projects to reduce the duration of the power outages their customers suffer. Recent research, however, suggests that residential customers already find their service quite reliable. If this sentiment proves widespread, distributors may be able to reduce their total network investment while making other service improvements.

Distributors regularly undertake massive and costly projects to improve the reliability of their systems: moving cables underground for protection from the weather, rearranging network architectures so that each outage affects fewer households, and increasing the capacity of transformers (which dilute power from the grid for domestic use) to cope more successfully with peak demand. In many countries, regulators require dis-tributors to meet set targets for permissible power outages and impose hefty fines for those failing to do so. Even without such rules, many distributors, believing that fewer, shorter power outages must be their customers' top priority, invest heavily in reliability programs. Over the past five years, for example, an Asian power company launched an extensive reliability effort, costing hundreds of millions of euros, to reduce the length of its annual service interruptions per customer from less than five minutes to less than two, thereby making itself more reliable than any other distributor we know. Of course, highly reliable service truly is a priority for business customers and for residential customers who suffer long power cuts because of high winds or downed power lines; the people of Barcelona, for instance, won't soon forget the many hours without electricity they endured in late December 2001. But it is doubtful that residential consumers who have reliable service—those in most developed markets and in some advanced emerging ones—want (or would be willing to pay for) service improvements of any type.

Our recent survey of one electricity distributor's customers, for instance, showed them to be largely content with their service and almost oblivious of service interruptions. More than half didn't know the total length of the outages experienced during the previous year—approximately two-and-a-half hours on average—and more than 80 percent of the remainder significantly underestimated their duration. In a comparison of two regions, one with much more reliable service than the other, the responses of customers in each showed that they had nearly identical perceptions of the reliability of their electrical supply (Exhibit 1). Finally, two-thirds of all survey respondents from Region A said that they would accept two hours of outages annually—even though they currently suffered, on average, only 70 minutes. This easygoing attitude may seem surprising, but the average consumer is asleep one-third of the day and not at home for another third. Moreover, although power may be interrupted, on average, for two hours a year, many customers suffer no outages at all. Research conducted in the United Kingdom in 1999 showed that its domestic consumers were even less bothered by the reliability of their electricity supply: 95 percent were satisfied with it and two-thirds thought that electricity companies shouldn't make additional investments to improve it.[1]

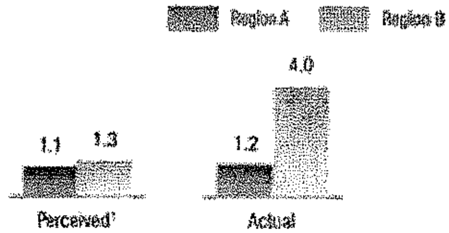
In any case, such investments may have little effect. When we analyzed the experience of distributors in several countries, we found no clear correlation between the amounts spent to improve the reliability of distribution networks and the duration of the power cuts in each region, even when the regions compared had similar terrains and climates (Exhibit 2). There are three reasons for these variations. First, some distributors are more efficient than others and can make themselves more reliable at lower cost. Second, returns on reliability investments (measured in minutes of improved reliability per euro spent) necessarily diminish beyond a certain threshold, which most distributors have already passed. Last, more than half of all power interruptions are beyond a distributor's control; they can occur because of constraints on generating capacity, outages in the transport network, or excavations by gas and water utilities, to cite a few examples. More investment in distribution networks can't solve these three problems.

So distributors should take the time to find out what people genuinely value. Companies with a good track record may find that

EXHIBIT 1

Contented customers

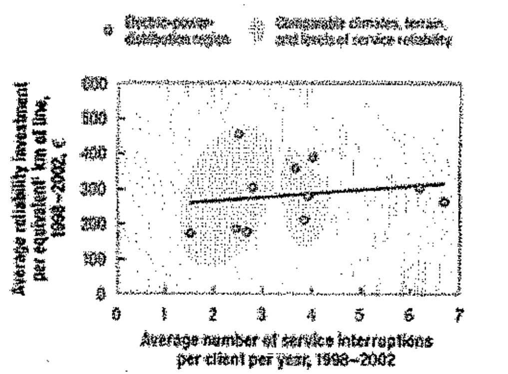
Duration of power cuts by region, 2001, hours



[1]130 customers responded to this question.
Source: McKinsey 2002 electricity consumer survey

EXHIBIT 2

Reliability investments bring unreliable results



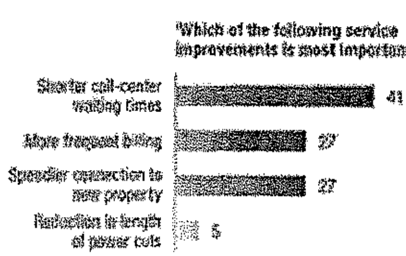
[1]Adjusted to account for different asset mixes—for example, percentage of line underground vs. percentage exposed, number of substations.

their customers, like those in the survey, would prefer more frequent and accurate billing, shorter call-center waiting times, or speedier connections for new properties (Exhibit 3)—improvements that would be relatively cheap to implement. If distributors can show that consumers actually want these cheaper improvements instead of the more expensive ones needed to improve the reliability of service, regulators might relax their present tough standards. Since these standards are usually reconsidered every two or three years, the distributors should undertake market research and draft their proposals in time to influence the next round.

EXHIBIT 3

What do customers really want?

Percentage of respondents (n = 177)



Source: McKinsey 2002 electricity customer survey

Meanwhile, distributors should analyze the root causes of their power cuts and rigorously evaluate any potential investments to improve the reliability of their networks. Two Central European distributors, for example, after rigorously reevaluating the reliability improvements they had intended to make, succeeded in reducing the planned cost by 20 percent while achieving their original targets. Many distributors will certainly find that redesigning their maintenance procedures—for example, by fielding additional emergency repair crews—could reduce the duration of their power outages a good deal more cheaply than could the usual large infrastructure investments.

About the Authors

Richard Hunter is a consultant and Ronen Melnik is an associate principal in McKinsey's Tel Aviv office; **Leonardo Senni** is an associate principal in the Milan office.

Notes

1The data come from an MORI poll—Quality of Supply, Attitudes of Business and Domestic Electricity Customers—conducted from January to March 1999 for the Office for Electricity Regulation (OFFER), which regulated the electricity industry in Great Britain at the time.

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www.platts.com

Electric Utility Week

August 4, 2003

University ties are key theme in Westar suit that also links Wittig to Boesky scandal

Tangled ties with the University of Kansas, long an undercurrent in the Westar Energy saga, boiled over late last week in a lawsuit that cites university-related links among key players as a major factor in the company's woes.

The suit also links ex-Westar boss David Wittig, now a convicted felon, to a former Wall Street mentor who was convicted of felony charges tied to the financial scandal surrounding Ivan Boesky.

The explosive material is contained in a totally new version of a shareholder derivative complaint (In the US District Court for the District of Kansas at Topeka, Case No. 03-CV-4081-JAR), which first became publicly available late July 31. The original suit was filed April 16.

The links between KU, Wittig and the majority of the board during his tenure have always been a subplot in the broader story of Westar's financial collapse and were developed somewhat further in the company's internal report about past management misconduct (EUW, 19 May, 1).

(continued on page 17)

With a twist, Senate gets energy bill out the door, sets up unusual dynamic for House negotiation

Struggling to meet an Aug. 4 recess date and avoid controversial Democrat-sponsored electricity amendments, Senate Republicans last week championed a return to the energy bill that passed in October 2002 but failed in later conference with the House. The apparently wily maneuver enabled leadership of the sharply divided Senate, which Republicans control by only two votes, to get an energy bill on the road to signature by President Bush.

"I'm a bit shocked and surprised that the Democrats agreed to it," said one utility representative. "It keeps alive the possibility of getting a major energy bill to the Rose Garden." Republicans said they believe they can work out differences between the 2002 Democrat-drafted bill and the bill written this year by Senate Energy and Natural Resources Committee Chairman Pete Domenici (R-N.M.) in the fall when they negotiate with the House, which passed an energy bill in April.

Both last year's and this year's Senate bills took similar tacks on major items—Public Utility Holding Company Act repeal,

(continued on page 6)

Northern Plains governors seek sanity in ongoing battle over Missouri River

One thing has not changed in the 200 years since Lewis and Clark first traversed the Missouri River's 2,341 miles—different folks have different ideas of how the vast waterway should be used.

Three upper plains governors think it is time to bring those interests together, and electric utilities will be watching closely.

The famed Lewis and Clark Expedition team were the first white men seen by most Native Americans who lived along the river from its junction with the Mississippi River at St. Louis to its origin in the Rocky Mountains of Montana.

Neither group knew about power generation, flood control, reservoirs, inland barge navigation, large-scale agricultural irrigation, recreational water use or habitats for endangered species of fish and birds.

For the past 60 years, however, those uses have shared the river under the Pick/Sloan Plan of 1944 and the Missouri River Bank Stabilization and Navigation Project of 1945.

There have been fights for almost that long about which uses should take precedence, culminating recently in dueling federal courts whose conflicting rulings threw thousands of megawatts

(continued on page 8)

INSIDE THIS ISSUE

The McGraw-Hill Companies

tolling agreement, a 222-MW deal with Black Hills Corp. for power from its Las Vegas Cogen plant.

Industry analysts last week said the contract sale may provide troubled Allegheny with some upside potential in the coming months.

Chris Ellinghaus, energy analyst for Williams Capital Group, said the deal would enhance Allegheny's flagging liquidity, eventually "providing the resources to allow the company to restructure tolling agreements in the West power book that are draining earnings and cash flow." He reiterated Williams' "buy" rating on Allegheny shares.

"The contract sale, along with the [$300-million] recent convertible placement [announced last week], resolve [the company's] near-term liquidity issues and should allow the company time to successfully restructure," he said in a research note.

While the DWR contract sale allowed the company to distance itself from bankruptcy, Ellinghaus cautioned "an investment in [Allegheny] is highly speculative, given the company's liquidity needs. We ultimately see earnings potential that supports the stock at significantly higher levels with improvement likely in 2004, but recognize that full realization of Allegheny's restructuring is not likely until 2005." Mike Worms, analyst for Harris Nesbitt Gerard, said Allegheny benefits from the deal because it will bring in needed cash and concentrate the company on its core businesses. "It is obviously a good deal for them," he said.

In a statement issued last Monday, Standard & Poor's said it considers Allegheny's sale of the contract "to be positive for liquidity, but the announcement does not affect the rating or outlook on the company."

"Although the sale of the CDWR contract will eliminate a primary source of cash flow volatility for the company and represents an important step towards restoring the company's creditworthiness, Allegheny has many other significant near-term challenges and the outlook on the company is likely to remain negative until it can bring its financial statement filings up to date and exhibit the financial strength to meet its bank loan covenants and upcoming debt maturities," the credit rating agency said.

MUNICIPALIZATION

Progress Florida gets to retain Casselberry franchise, other cities still in negotiations

After tough negotiation, the city commission of Casselberry, Fla., last week approved a new 30-year franchise agreement with Progress Energy Florida that gives the community the highest franchise fee it pays in the state, 6%, and a "favored nation" clause that entitles the city to a better deal if Progress gives a better one to any other municipality.

The city also gets a direct reimbursement of $1.75-million for expenses it incurred while the franchise was in dispute. And Progress will pay property taxes directly rather than deduct them from franchise fee payments as in the previous franchise.

To get at what Casselberry has said was the primary reason it contested renewal of the franchise, it won a provision in the agreement that requires a reliability study every five years by outside consultants to evaluate Progress' service and binds the utility to rectify reliability problems identified.

Casselberry was one of a handful of cities in southwest Florida that had refused to renew their franchise agreements with the utility, primarily, they said, because of reliability problems. But Casselberry's concerns were addressed in the new deal, according to Tony Segreto, the city's public works director. "It was a good deal," he said. "They offered us more than they have anyone else in the state."

Progress is still in negotiation with the cities of Longwood, Winter Park and Belleair to renew their franchise agreements.

Longwood city commissioners voted once to approve a 30-year franchise agreement and a legal settlement with the utility that would pay the city $440,000. The agreement must be approved again in an Aug. 4 vote. "We are cautiously optimistic with Longwood," said a Progress spokesman.

Winter Park has scheduled a Sept. 9 public referendum to municipalize, while Belleair is in the middle of arbitration hearings over the value of its grid in preparation for municipalization.

PLANNING

McKinsey sees utilities overspending on reliability more than customers care

Utilities over-emphasize the value of reliability to customers, and are investing too much to upgrade an aspect of service that residential customers already find satisfactory, according to consulting firm McKinsey & Co.

An article in the third-quarter issue of *The McKinsey Quarterly*, entitled "What Power Consumers Want," asserts that utilities can reduce their network investments and make cheaper service improvements that customers value more.

The article found that electricity distributors regularly undertake big projects such as burying lines, upgrading transformers and rearranging network architecture so outages affect fewer households. In most cases, they are prodded by regulators, who require utilities to meet reliability targets, and impose heavy fines if they fall short. McKinsey notes that one unnamed Asian utility pursued a project worth hundreds of millions of euros to reduce annual interruptions from less than five minutes to less than two.

"But it is doubtful that residential customers who have reliable service—those in most developed markets and in some advanced emerging ones—want (or would be willing to pay for) service improvements of any type," the article states. Most residential customers in a recent survey under-estimated the duration of their utility's interruptions, it notes. Further, the respondents said they would accept two hours of outages annually, even though their utility's interruptions average only 70 minutes.

"This easygoing attitude may seem surprising, but the average consumer is asleep one-third of the day and not at home for another third," the article notes. "Moreover, although power may be interrupted, on average, for two hours a year, most customers suffer no outages at all."

Further, investments do not always improve reliability. McKinsey found "no clear correlation between the amounts spent to improve the reliability of distribution networks, and the duration of power cuts in each region, even when the regions compared had similar terrains and climates." That is because more efficient distributors can make themselves more reliable at lower cost. In addition, "returns on reliability investments...diminish beyond a certain threshold, which most distributors have already passed," the authors state.

Finally, more than half of interruptions are beyond utilities' control, because they stem from generation constraints, outages in the transportation network, or excavations by gas and water utilities. "More investment in distribution networks can't solve these problems," the article says.

Therefore, utilities "should take the time to find out what people genuinely value," McKinsey advises. Customers in the survey said they would prefer quicker connections for new properties, more frequent and accurate billing, and shorter call-center wait times. "If distributors can show that customers actually want these cheaper improvements, instead of the more expensive ones needed to improve the reliability of service, regulators might relax their present tough standards," the article says.

At the same time, utilities may be able to reduce reliability-upgrade costs by better evaluating proposed investments. By re-designing maintenance procedures—fielding additional repair crews, for instance—they can often reduce the duration of power outages significantly more cheaply than by making infrastructure improvements.

Utilities urged to push for uniform rules on power supply purchasing

PacifiCorp, Calpine and the Natural Resources Defense Council are jointly urging utility regulators nationally to provide uniform rules for how electric utilities should acquire new power supplies for customers.

The proposal was made at a meeting of the National Assn. of Regulatory Utility Commissioners in Denver. Currently utility commissions in various states differ in how they deal with approving utilities' proposed electric resource portfolios.

The group is taking this unusual step because with the demise of the merchant power industry, utilities are taking the lead in providing power either by building their own plants or buying power from independent power producers.

Creating a transparent process and providing incentives for developing resource portfolios could shield utility consumers and shareholders alike from unreasonable costs and risks, said Don Furman, PacifiCorp senior vice president of regulation and external affairs. Moreover, with transparency, a state commission is more likely to look favorably on rate recovery when a utility solicits resources, a company spokesman said.

"A common approach to resource procurement rules shared across the states is particularly important for utilities and resource developers with business in multiple states," Furman said.

The group recommended that the commissions create a public process for upfront regulatory review and approval or disapproval of utilities' proposed electric portfolios. They want to ensure that utilities are compensated for the costs and risks taken in managing power portfolios for customers and eliminate unintended and unnecessary financial disincentives for utility investments in energy efficiency. They are urging commissions to set procurement requirements based upon reliability and economic considerations.

The group also recommends using a public process to identify resource procurement requirements and the specific resource criteria that will meet those requirements, including long-term energy efficiency improvements and short-term demand reduction options.

A combination of market based and regulatory initiatives is the best solution to ensure utilities are able to deliver reliable electric service, they said.

The NRDC, a non-profit environmental advocacy organization, said it joined PacifiCorp and Calpine because their plan identifies steps toward reviving long-term investment in more efficient and cleaner technologies, which are crucial to making environmental progress n the power industry.

A Calpine spokesman said, "In this post-Enron market, companies like Calpine no longer are willing to build on a purely merchant basis. "We need long term contracts in place before we obtain capital. We would like to see a fair and consistent playing field and solicitations that have an unbiased outcome free from affiliate abuse or insider trading."

Midwest Gen to operate three coal plants, 580 MW, despite Exelon contract release

Midwest Generation, citing an improving outlook for less expensive coal-fired generation, has decided to continue operating three older coal units representing 578 MW of generating capacity in northern Illinois next year despite Exelon's recent announcement it will not buy power from them in 2004.

In late June, Exelon, parent company of Commonwealth Edison, Illinois' largest electric utility, decided not to exercise its contractual right to purchase 262 MW from Will County Unit-3, 216 MW from Crawford Unit-7 and 100 MW from Waukegan Unit-6 (EUW, 30 June, 5).

The three units all were built in the 1960s and 1970s.

Under a five-year purchase power agreement entered into by Exelon and Midwest Gen in late 1999, following Midwest Gen's acquisition of seven power plants from ComEd, Exelon is allowed to exercise call options on certain amounts of power

National Energy Board
Office national de l'énergie

A Compendium of Electric Reliability Frameworks Across Canada

June 2004

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TABLES

FIGURES

ACRONYMS

AC	alternating current
AESO	Alberta Electric System Operator
ATC	available transfer capacity
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
CAIDI	customer average interruption duration index
CEA	Canadian Electricity Association
DC	direct current
DR	demand response
DSM	demand-side management
ECAR	East Central Area Reliability Coordination Agreement
ECSTF	Electricity Conservation and Supply Task Force
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission (U.S.)
FRCC	Florida Reliability Coordinating Council
HQ	Hydro Québec
IMO	Independent Electricity Market Operator (Ontario)
IOR	index of reliability
IPL	international power line
LDC	local distribution company
MAAC	Mid-Atlantic Area Council
MAIN	Mid-Area Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent Transmission System Operator, Inc.
NEB	National Energy Board
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council

NSPI	Nova Scotia Power Incorporated
NWT	Northwest Territories
OATT	open access transmission tariff
OEB	Ontario Energy Board
P.E.I.	Prince Edward Island
RA	Reliability Authority
RTO	regional transmission organization
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool Inc.
UARB	Nova Scotia Utility and Review Board
WECC	Western Electricity Coordinating Council

Energy Units

Prefixes		*Equivalent*
k	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Power Measures

kW	kilowatt	= 10^3 watts
MW	megawatt	= 10^6 watts
GW	gigawatt	= 10^9 watts
TW	terawatt	= 10^{12} watts

Energy Measures

		Energy Content
kW.h	kilowatt hour	3.6 MJ
MW.h	megawatt hour	3.6 GJ
GW.h	gigawatt hour	3.6 TJ
TW.h	terawatt hour	3.6 PJ

Note: A kilowatt hour is the amount of energy required to operate ten 100-watt light bulbs for an hour.

Metric to Imperial Units

1.0546 GJ	= one million British thermal units (Btu)

FOREWORD

This report, *A Compendium of Electric Reliability Frameworks Across Canada* (the Compendium), has been compiled by the National Energy Board (NEB) as part of its regulatory mandate to monitor Canadian energy markets. The Compendium follows two electricity Energy Market Assessments entitled *Canadian Electricity Trends and Issues, May 2001 and Canadian Electricity Exports and Imports, January 2003*. These reports are intended to contribute to the public's understanding and awareness of current developments in the Canadian electricity sector.

The timing of the Compendium is guided by the ongoing issues surrounding the assurance of reliability in restructured electricity markets, and by the 14 August 2003 power blackout, which has raised concerns about the reliability of the interconnected North American transmission grid. The objective of the Compendium is to provide a succinct yet comprehensive description of reliability frameworks throughout Canada. It is not an assessment or judgment of the electric reliability of any specific province or territory in an absolute or comparative sense. Additionally, readers may find this report can provide baseline information and regional context for the discussions following the publication of the *Final Report on the August 14, 2003 Power Blackout in the United States and Canada: Causes and Recommendations* by the U.S.-Canada Power System Outage Task Force.

The Compendium is based to a significant extent on information obtained through consultations with interested parties, representing the electric power industry in Canada, power consumers, provincial governments, regulatory agencies and public interest groups. The NEB appreciates the information and comments it received from all participants.

EXECUTIVE SUMMARY

This Compendium has been compiled by the National Energy Board (NEB) as part of its regulatory mandate to monitor Canadian energy markets. The report is motivated by two main developments: the restructuring of electricity markets in North America; and the 14 August 2003 power blackout that affected most of Ontario, a small portion of generation in Québec and a large part of the U.S. Midwest and Northeast.

Electricity is delivered through an intricate network of interconnected high-voltage transmission lines and power generation facilities which comprise the bulk power system. To ensure reliable service, this system must be precisely monitored and controlled. From the consumer standpoint, electric reliability means continuity of service and acceptable power quality. From the supply standpoint, there are two basic aspects to reliability: planning for adequacy of generation and transmission infrastructure; and operational reliability. Operational reliability depends on the essential activities of system operators to monitor and respond to changing conditions on their own and adjacent power systems.

The electric power industry has developed a number of ways to measure reliability performance. The most common measures track the frequency and duration of outages. While power outages resulting from bulk system disruptions occur occasionally, most service disruptions affecting consumers occur at the distribution level. However, when disruptions on the bulk system do occur, they can have significant and widespread impacts, including economic and social costs. Economic costs may include lost industrial production, equipment damage, and spoilage of raw materials and food. Social costs may include the inconvenience of lost transportation, uncomfortable building temperatures and personal injury. For example, as a result of the 14 August 2003 blackout, factory shipments in Ontario were down by $2.3 billion.[1]

A variety of technologies and infrastructure investments can be used to enhance reliability; however, the costs must be compared with the potential reliability benefits gained to determine whether such investments are worthwhile. System reliability can be fortified by interconnections with adjacent jurisdictions. These interconnections can also function as important conduits for interprovincial and international trade. While reliability and trading benefits are associated with interconnections, events have also occurred where major system disturbances have spread or "cascaded" from one jurisdiction to another. To a great extent, the provision of reliability has focused on electricity supply. However, there is now increased interest in enhancing reliability from the demand side, through development of demand response programs.

Most responsibility for regulatory oversight of the electric power industry lies with the provincial governments and their respective regulatory agencies. The federal government considers reliability issues when developing electricity policy and regulations for interprovincial and international trade.

1 *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004, P.1. The report can accessed at www.neb-one.gc.ca under *Canada-U.S. Power System Outage*.

Utilities have had a mandate to provide reliable electricity at the lowest practical cost. For bulk power systems, this requires planning for adequacy of supply in generation and transmission and then ensuring reliability in system operations. This coordination could occur through a vertically-integrated utility or, in an unbundled market structure, the activities of market participants may be coordinated by an independent system operator.

For interconnected bulk power systems, the North American Electric Reliability Council (NERC) and its regional councils, in which most Canadian electric utilities/system operators are members, have been assuming the main responsibilities for setting reliability standards and operating policies. Membership in NERC is voluntary, with standards and policies compliance enforced mainly through peer pressure.

The challenges presented by the unbundling of generation, transmission and distribution in restructured markets have prompted calls for legislation requiring that reliability standards be mandatory and that there be consequences for not meeting standards. Proposed U.S. energy legislation calls for the establishment of an independent Electric Reliability Organization (ERO), with regulatory oversight in the U.S. by the Federal Energy Regulatory Commission (FERC). It is not currently known whether NERC (in a modified form) or another organization will constitute the ERO. In the interim, NERC has resolved "to work closely with FERC and other applicable federal, state, and provincial regulatory authorities in the United States, Canada and Mexico to ensure that the public interest is met with respect to compliance with reliability standards."[2] Further support for mandatory, enforceable standards was demonstrated in the first recommendation of the Final Report on the August 14, 2003 Blackout.[3]

The Compendium describes the reliability framework and identifies reliability issues by province and territory. The type and extent of oversight varies. In some jurisdictions, industry participants have a legislated obligation to provide reliable electric service and may be subject to financial penalties for unsatisfactory reliability performance (e.g., Ontario and Québec). In other jurisdictions, utilities are required to report periodically on their reliability performance. At the federal level, the NEB takes into account reliability when considering applications to construct and operate international power lines. The NEB requires the applicant to provide information on the impacts of the operation of the proposed power line on the power systems in other provinces, i.e., other than those provinces through which the line passes. Similar considerations apply in the authorization of electricity exports.

With restructuring, the centralized planning function traditionally held by the vertically-integrated utility is being replaced by other mechanisms that involve shared responsibilities among different entities. Ontario and Alberta have largely restructured their industries; British Columbia has recently undertaken further restructuring initiatives; and imminent changes are expected in New Brunswick and Nova Scotia. In several provincial jurisdictions (e.g., Ontario, Québec, New Brunswick), generation adequacy is an issue that has initiated public interest. This has led to proposals to build new generation capacity and new interconnections. In Ontario and Alberta, there are also issues surrounding the building of transmission capacity.

2 NERC Board of Trustees, 10 February 2004.

3 *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, pp. 13, 140.

Summarizing points are as follows:

Reliability frameworks are diverse and evolving.

The reliability frameworks, in terms of the roles of the provincial governments, regulators and market participants, are diverse with the type and extent of oversight varying among the provinces. As restructured markets are introduced and mature, and provincial electric policy changes, the roles for maintaining reliability tend to evolve as well. Often, the provincial approach to ensuring reliability is augmented by the imposition of a legislated obligation on utilities to provide reliable electric service.

Restructuring introduces opportunities and challenges in maintaining reliability.

In a restructured market, many aspects of reliability management and oversight become more complex as the number of market participants increases and reliability responsibilities are shared among a number of entities. To date, the implementation of restructuring has both facilitated and impeded reliability. The circumstances brought about by restructuring have been a driving force behind efforts to develop a system of mandatory reliability standards, which would be monitored and enforced through a compliance program with financial penalties.

Reliability expectations vary.

A survey by the Canadian Electricity Association found that Canadian distribution systems were available 99.95 percent of the time during the five-year period 1998-2002.[4] Expectations about an acceptable level of reliability, with accompanying costs, vary across consumer sectors and regions. For industrial users, and increasingly for commercial and residential users, good reliability includes continuity of service and appropriate voltage control. The challenge for industry, governments and regulators is to find the optimum level of reliability given the diverse requirements.

Reliability can be gauged using performance measures.

Several measures have been developed by industry to gauge reliability performance, with the most common addressing the duration and frequency of interruptions. Performance measures can be used to highlight specific issues within a power system and to compare performance with other systems. Although governments and regulators usually have access to utility performance data on reliability, depending on the province, public access varies. Notwithstanding that some performance data may be sensitive, commercially or otherwise, there is a public desire for greater transparency and availability of information. Furthermore, the U.S.-Canada Power System Outage Task Force recommends the establishment of an independent source of reliability performance information.

Reliability has a cost.

Reliability can be improved by making investments in infrastructure and technology. Investments can be aimed at outage prevention, outage containment and service restoration. To optimize reliability investments, planners must ensure the cost of initiatives is justified financially, socially and environmentally in terms of benefits or avoided costs. Utilities and other planners are challenged with achieving an acceptable level of reliability while keeping rates at reasonable levels.

4 Excluding the Quebéc/Ontario ice storm in 1999, which reduced availability to 99.65 percent.

Interconnections enhance reliability.

Under normal operating conditions, interconnections between power systems improve reliability and provide commercial benefits. However, a disturbance in one system, if it is severe enough, can affect adjoining systems, thereby exposing a local system to regional weaknesses. The consensus is that the benefits outweigh the potential risks and the industry trend is toward strengthening the overall interconnected system.

Demand-side actions can enhance reliability.

Consumer behaviour and actions can enhance reliability through reducing overall electricity consumption (demand-side management) and by deferring consumption to non-peak periods (demand response). To improve the success of demand programs, there is a need to develop proper incentives to motivate consumers to respond effectively.

Introduction

This report addresses the provision of electric reliability across Canada and, specifically, the roles and responsibilities of the electric power industry, governments and industry regulators to ensure reliability. Electric reliability means continuity of service and acceptable power quality. This requires precise coordination and control in the electric power system from the source of generation through transmission and distribution.

The National Energy Board (NEB) has compiled this Compendium as part of its responsibility to monitor and report on developments in energy markets. This report is motivated by two main developments: the ongoing restructuring of electricity markets in North America; and the 14 August 2003 power blackout, which affected most of Ontario and a large part of the U.S. Midwest and Northeast, an area with a population of 50 million.

Restructuring refers to the unbundling, or separation, of the generation, transmission and distribution functions. Until the early 1990s, these functions were mainly performed by vertically-integrated utilities. Restructuring has evolved as competition was introduced in generation and there was a need to allow new players to have access to the electric transmission network. This separation has highlighted the need to ensure reliability. Across Canada, the extent of restructuring varies among the provinces, and the approach to ensuring reliability also varies.

According to the Final Report on the August 14, 2003 Blackout, the blackout was initiated by a combination of events in Ohio, which caused an initial loss of transmission and generation facilities to spread or “cascade” across the electrical interconnections into neighbouring states and Ontario. This event was the largest blackout in the history of the North American power business. Although power was restored to most of the area within a day, it took about one week before service was returned to normal in the entire region.

The North American Electric Reliability Council (NERC) has reported at least five other large outages since 1965 with widespread impacts. Three of these occurred in 1996 and 1998 and, on separate occasions, directly affected all provinces west of Québec. The 14 August 2003 blackout has further called into question the overall reliability of the bulk power transmission system, or interconnected grid. This is the system of electric generating facilities and high voltage transmission wires that produce and transfer power to local distribution systems (and other transmission customers such as large industrial consumers) either within a region or into other jurisdictions. All the provinces are part of the interconnected grid and hence participate in inter-regional transfers between provinces and with adjacent states to improve reliability and engage in commercial trade.

Chapter 2 presents an overview of reliability: addressing what is meant by electric reliability; how it is measured; and the roles and responsibilities of industry, governments, and regulators in ensuring reliability. Chapter 3 presents regional information for the provinces and territories commencing with a description of the market, and then discussing the reliability framework and regional issues. Chapter 4 concludes with summarizing points.

Overview of Electric Reliability

An intricate network of interconnected high-voltage transmission lines and power generation facilities is responsible for the delivery of electricity. This complex commodity is invisible, it moves at the speed of light along the path of least resistance, and it cannot effectively be stored.[5] This means the amount of electricity generated and delivered must continuously match the amount of energy that is being demanded. The grid, which includes the high-voltage lines involved in the transfer of power between generating plants and customer loads (mainly distribution companies and large industrial customers), must be precisely monitored and controlled to ensure the correct amounts of power are flowing in the correct directions. Power must then be stepped down to a lower voltage and delivered through distribution networks to the places where it is needed.

2.1 What is Electric Reliability?

When a member of the household flips a switch to turn on the lights, they are normally assured that the lights will go on. Yet, occasionally, the lights suddenly go out and electric devices shut down. These events, known as blackouts or power outages, are not only inconvenient, they can be costly. For most people, the cost may be just a few moments in the darkness and the effort to reset the time on a number of clocks. Depending on the extent and duration of the outage, however, the costs can be much higher. Traffic light outages can lead to car accidents; the loss of air conditioners can lead to heat stroke; the loss of heat in homes can lead to damaged water pipes; and the loss of refrigeration can lead to food spoilage. Electrical outages can have innumerable other costs. Even slight changes in electrical voltages can have high impacts. These electrical disturbances can shut down, or otherwise result in millions of dollars of losses, for such processes as computer chip or glass manufacture.

Electric reliability means that electric service will be delivered to the consumer with a high degree of assurance. As implied above, this means that the lights will go on and other diverse requirements such as heating, air conditioning, computing services, and electrical processes and control in industry, can be met on demand. To ensure this occurs, the electric power system, from the source of generation through transmission and distribution, must be reliable.

Aspects of Reliability

In every electric power system there are two main aspects to reliability. The first is adequacy of supply, which involves having enough generation and transmission capacity to meet projected system needs. The second aspect is short-term or operating reliability, which requires that a system be able

5 This report mainly addresses the reliability of supply of electricity through the (AC) bulk power system, which is the system of electric generating facilities and high voltage transmission wires that produce and transfer power to local distribution systems. Of course, electricity can be stored in batteries for (DC) use at the point of final consumption. This normally accounts for a minor amount of total electricity use. At the present time, storage in batteries is not practical in the quantities required to be useful for bulk power shipments.

to withstand disturbances or contingencies and be able to continue operating even if there are problems with the infrastructure or other interconnected systems. This may be accomplished by maintaining reserves of generation and transmission capacity.

The two aspects of reliability interact. For example, if, in response to a contingency, an operator uses the reserve margin to meet load, instead of curtailing load, the reserve level will dip. This approach ensures supply adequacy but leaves the system operationally vulnerable should a further need for the reserve margin arise. Given the interrelated nature of these two aspects of reliability, systems are planned to be both adequate and operationally reliable. New generation may be strategically sited close to the load centre to meet both adequacy requirements and enhance the operational reliability of the system. Both aspects must be considered when balancing the costs of reliability efforts and the economic impact of power outages.

2.2 How is Reliability Measured?

The electric industry has developed a number of different ways to measure reliability performance. For example, the reliability of generating units can be assessed from information on their actual utilization over time relative to full capacity (operating factor) and information on unscheduled unit outages. The reliability of transmission facilities is measured by indicators such as the frequency of outages of specific components (e.g., transformer outages) and broader measures such as the performance at the delivery points to distribution systems. Measures that provide an indication of reliability of distribution systems have also been developed.

The Canadian Electricity Association (CEA) publishes data on the performance of generation and transmission equipment and specific performance indicators for distribution systems across the country. Some of the more common reliability measures for distribution systems are set out in Table 2.1.

TABLE 2.1

Distribution System Performance Indicators[1]

Measure	What it Measures	Canadian Average (1998-2002)
Index of Reliability (IOR)[2]	portion of time the system is available	0.9995
System Average Interruption Frequency Index (SAIFI)	number of interruptions	2.4 per year
System Average Interruption Duration Index (SAIDI)	number of hours of interruption	4.4 per year
Customer Average Interruption Duration Index (CAIDI)	average length of each interruption	1.8 hours

1 2002 *Annual Service Continuity Report on Distribution System Performance in Electrical Utilities*, CEA. While data at the Canadian level are available to the public, the individual company data are only available to participants in the survey. Uses of this information include company benchmarking for internal purposes and in submissions to regulators.

2 IOR = [(8760-SAIDI)/8760]; number of hours in a year is 8760.

Distribution indicators provide a bottom-line measure of reliability from the standpoint of the consumer. For Canadian distribution systems overall, IOR was stable in the range of 0.9995 for the five-year period 1998-2002. This means that, on average, Canadian distribution systems were available 99.95 percent of the time (excluding the impact of the Québec/Ontario ice storm, which reduced availability to 99.65 percent).

Some of the most common causes of distribution outages include: scheduled outages, loss of supply, tree contact, lightning, defective equipment, adverse weather, and the human element.[6] On average, over the five-year period, approximately 75 percent of all customer outage incidents and 85-90 percent of all customer outage hours were due to distribution system problems.[7] The remaining outages were due to loss of supply, which is a proxy for transmission and generation outages.

These results suggest that, from the consumer viewpoint, the reliability of the bulk power system is somewhat higher than the distribution system. This is consistent with the general view that the flexibility in the bulk delivery system enables system operators to compensate for contingencies. For example, if a generating unit experiences a technical problem and must shut down, the system operator can call on reserve margins to meet demand. If a transmission line trips off, the power can flow across different lines so that demand is still satisfied in each area. In the absence of exceptional circumstances, consumers will not be aware of the disturbance. However, when larger bulk system outages occur, they affect more people and tend to last longer, as demonstrated by the 14 August 2003 blackout.

Distribution systems, on the other hand, have less flexibility because they have less redundancy built into them. The cost of duplicating the infrastructure would be high and, as disturbances on these systems do not affect as many people, the benefits would be small. A lack of redundancy and generally longer distribution lines also mean that rural consumers experience lower reliability than urban consumers.

2.3 How is Reliability Enhanced?

2.3.1 Investment[8]

A variety of technologies and infrastructure investments can be used to enhance reliability; however, their costs must be compared with the reliability benefits gained to determine whether it is worthwhile to consumers. System planners have generally adopted a criterion that it is appropriate to have no more than one day of outages in a ten-year period, and use detailed system models to develop scenarios to achieve this level of reliability. Companies then compare the costs of different methods of achieving the required level of reliability, and generally use the lowest-cost method. This approach estimates the appropriate generation reserve margins and spare capacity in transmission systems and tends to be the general approach to reliability planning.

Another way of determining the appropriate amount to invest in reliability is to compare the costs of outages (i.e., the costs resulting from lower reliability) with the costs of providing greater reliability. When reliability is low, outages will be frequent and the negative impacts on power consumers will be high. As reliability improves, as a result of reliability investments, outages will be less frequent. In this approach, planners try to find the level of reliability resulting in the lowest overall costs (Figure 2.1). If infrastructure investments are less than the ideal, society will incur outage costs that are greater than the savings in infrastructure. If infrastructure investments are greater than the ideal, society is spending more on infrastructure than it is saving in outage costs.[9]

6 The human element includes errors in system installation and operation, and deliberate damage or sabotage.

7 *2002 Annual Service Continuity Report on Distribution System Performance in Electrical Utilities*, CEA.

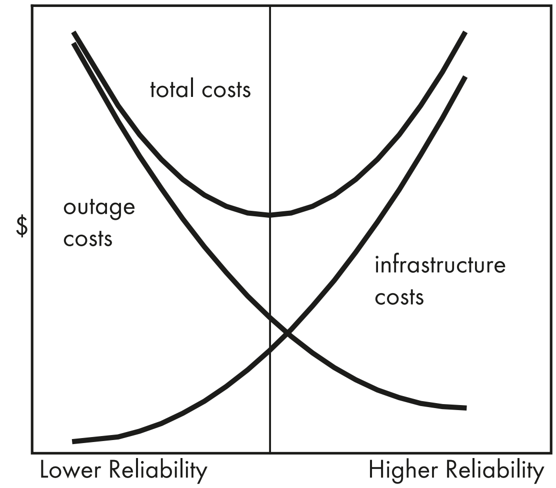
8 This section draws on concepts developed in *Reliability Evaluations of Power Systems*, Billinton, R., and Allan, R.N., Second Edition, Chapters 1 and 13.

9 Outage costs could include a broad range of economic and social costs. Economic costs might include lost industrial production, equipment damage, spoilage of raw materials or food. Social costs might include the inconvenience of lost transportation, the loss of leisure time, uncomfortable building temperatures and personal injury.

There is some debate on the estimation of outage costs, and who exactly might benefit from reliability investments. It may even be difficult to distinguish between investments in reliability and investments in infrastructure for commercial reasons, an example of the latter being to improve trading between interconnected electric systems. Notwithstanding these issues, the important point addressed in this approach is that investments in reliability yield benefits, but, after some point, the benefits are less than the costs. This issue is recognized in the legislation and regulations in a number of provinces, which require that investments not be undertaken for reliability in the absence of other considerations such as efficiency and the prudence of incurred costs.

FIGURE 2.1

The Cost of Reliability[1]



1 Billinton, R. and Allan, R.N., Figure 1.3.

2.3.2 Technology

Technology has an important role to play in enhancing reliability. Technological innovation may contribute to system adequacy by increasing the capacity in existing right-of-ways. This can be accomplished through improved efficiency in transmission, such as through FACTS devices, and other devices that allow more precise measurement of the capability of transmission lines, thus enabling operations closer to thermal limits.[10] These technologies are costly and cost recovery may be at risk, especially in markets where there is uncertainty about the pricing of future transmission services.

Constraints on constructing new transmission facilities may be alleviated by building centralized power plants closer to load centres. This could also be accomplished with distributed generation from the LDC or installed by end-use consumers, such as large industrial customers. The solution may include selling power back to the grid, which would require reverse metering.

From an operating standpoint, adaptation of new communications and control tools can improve the monitoring of the real-time operation of the grid. This would result in better understanding of operating conditions, including early warning of contingencies in the immediate and adjacent control areas.

2.3.3 Inter-Regional Trade

Under normal operating conditions, system reliability can be fortified by interconnections with adjacent jurisdictions. All provinces are interconnected with neighbouring provinces, although most of the provincial networks have larger interconnections (as measured by power transfer capability) with the bordering states to the south. Provincial interconnections have been built to provide reliability and, in some cases, optimize the construction and utilization of generation resources. For example, reserve margin requirements tend to be lower on interconnected systems since a larger pool

10 FACTS (Flexible AC Transmission System) devices include a variety of electronic devices used to improve control and stability of the transmission grid. The increased ability to direct power flow and the very fast response to system conditions enable the transmission system to be operated closer to thermal limits, thus improving transmission efficiency.

> ### *Time-of-Use Metering*
>
> The feasibility of time-of-use (TOU) metering is relatively well established for large-volume customers who have the capability to shift load requirements and where the pricing regime provides incentives through TOU rates. Such programs are in place in a number of provinces.
>
> TOU metering is technically feasible for small-volume customers, at the household level, using current electronic microprocessor technology. For example, some meters are capable of recording energy usage in 15-minute intervals and storing the data in Read-Only-Memory. The meters may be programmed to communicate with the utility every 24 hours, to download data to their customer billing system. Communications with the utility's billing system may occur by a landline or cellular telephone, digital paging or radio frequency. The installed cost of these meters could be as high as $1100 per household. However, depending on the specific application and extent of market penetration, the costs of TOU meters may be closer to $400 and lower.
>
> While there is not widespread use currently, there are some programs in place. For example, Hydro-Québec has an experimental TOU program involving approximately 400 residential customers, who can benefit from lower rates during off-peak periods. Currently, Hydro-Québec does not intend to offer a large scale TOU residential program and has indicated that the cost of the meters and billing costs could be a barrier to TOU applications.
>
> Princeton Light and Power, a municipal utility in B.C., offers TOU rates to all residential and commercial customers along with automation for controlling appliances and shifting consumption from peak to off-peak periods. Roughly 100 of 3 000 customers are on the program and participation is growing. In this case, the cost savings in power purchased by the utility pay for the program.
>
> The growth in TOU metering for small-volume consumers will be governed by such factors as: reductions in the cost of metering (including billing expenses); the difference between peak and off-peak electricity prices; and the capability of these consumers to shift load from peak to off-peak.

of generation is available to respond to system disturbances. The territories are neither interconnected, nor do they have connections with the provinces or the U.S.

Interconnections also provide conduits for interprovincial and international trade, enabled by the diversity of daily and seasonal power usage between importing and exporting jurisdictions. Hydro systems, which can store water during off-peak periods and then release the water for power production during peak periods, are well suited to benefit from this diversity. Therefore, provinces with large hydro endowments and water storage capacity, such as Québec, Manitoba and B.C., have been the largest net exporters to the U.S.

While there have been reliability and trading benefits associated with interconnections, there are also risks, and there have also been a number of circumstances where major system disturbances have spread or cascaded from one jurisdiction to another. The most recent of these occurred on 14 August 2003.

2.3.4 Demand-Side Management (DSM) and Demand Response (DR)

To a great extent, the provision of reliability has focused on electricity supply. However, consuming patterns can have a significant impact on the supply/demand balance, drawing on the conservation notion that, within certain limits, it can be cheaper to save a kilowatt hour than it is to produce one.

The implementation of DSM initially occurred in the late 1980s and early 1990s. From the standpoint of the utility customer, these programs were usually non-price related. Utilities recognized that they could reduce costs by funding conservation programs such as energy audits and provide subsidies for more efficient equipment and appliances. The benefit to the consumer was a lower power bill. The benefit to the utility was to share some of the cost savings, and thus improve the return on their regulated assets. In effect, these programs substituted for a price mechanism that would send signals to consumers to reduce consumption in times of tight supply. This is the approach taken today in such programs as Power Smart in B.C. and Manitoba.

Another form of non-price incentives was employed in California during the electricity crisis in the western U.S. in 2000-2001, a period when wholesale prices in California rose above "capped" retail prices. In one program, Pacific Gas & Electric compensated consumers who reduced consumption from previous year levels. The payments were funded from the cost savings to the utility from not having to purchase expensive power on the open market. The program was credited with making a significant contribution to balancing electricity loads with resources as the western power crisis dissipated.

The advent of competitive power markets has introduced DR programs. Such programs allow consumers to reduce consumption at higher price levels during peak periods by having rates set on a real-time basis, i.e., time-of-use rates. DR programs complement more traditional mechanisms such as the interruptible contracts available to large consumers. In an interruptible contract, the utility may curtail service during periods of tight supply; however, it charges lower rates than for firm service, reflecting the risk of curtailment.

DR benefits larger consumers who have the capability to shift demand to off-peak periods and who have the necessary metering equipment. Ontario, for example, has two programs administered by the Independent Electricity Market Operator (IMO) that provide incentives to reduce demand during peak periods: the dispatchable load program, which allows consumers to reduce consumption when prices reach a certain level; and the Hour Ahead Dispatchable Load program, which enables wholesalers to address differences in planned versus actual consumption and then respond to instructions from the IMO. Other mechanisms to increase demand response in Ontario are under review.[11] Currently, DR programs have less direct potential for smaller consumers due to the availability and cost of time-of-use metering.

The reliability benefits of DR programs are complemented by price benefits. In competitive wholesale markets such as in Ontario and Alberta, wholesale prices in peak periods are set by the most expensive generation sources. Thus, it is possible that a relatively small reduction in demand can result in a large price reduction. Moreover, due to the price setting mechanism in the competitive market, the price reduction applies to total demand; therefore, even consumers who cannot reduce consumption may benefit from lower prices. This concept is illustrated in Figure 2.2.

2.4 Who is Responsible for Ensuring Reliability?

The electric industry, the provincial and territorial governments and their regulators, and the federal government have responsibilities to ensure electric reliability in Canada. An overview of these responsibilities follows. Chapter 3 provides a description of how responsibility is shared in each province and territory.

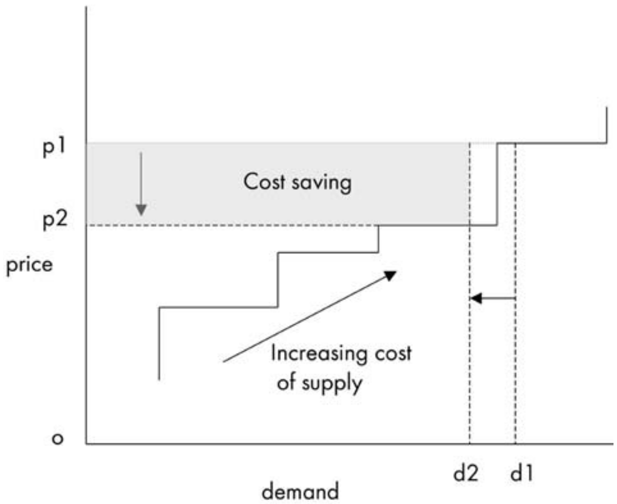
2.4.1 The Electric Industry

Traditionally, vertically-integrated utilities, which provide generation, transmission and distribution, have had total responsibility for ensuring power is delivered to consumers under specific terms and conditions (Figure 2.3). This "obligation to serve" was required in return for the utility being granted a monopoly franchise, subject to provincial or territorial regulation. During the last decade, a number of provinces have restructured so that separate entities are now responsible for providing these functions.

11 *Tough Choices: Addressing Ontario's Power Needs*, Electricity Conservation and Supply Task Force, January 2004, pp. 36, 37.

FIGURE 2.2

Impact of Reduction in Peak Electricity Demand



Source: NEB.

Impact of Demand Response Programs

The effects of DR programs are shown in this diagram, which provides a simple representation of price determination in a competitive bulk power market. The "stepped" supply curve, rising to the right, illustrates how higher-cost blocks of power are offered into the market at higher demand levels. The reduction in demand, from d1 to d2, enables demand to be met with lower cost supply. Consumers, such as large industrial consumers, benefit by shifting consumption to a period of much lower prices, say in the evening or overnight. Consumers who are unable to reduce demand, such as residential consumers, may also benefit, as illustrated by the price reduction from p1 to p2 and the total cost saving represented by the shaded area.

FIGURE 2.3

Unbundled Electricity Service

In provinces such as Ontario and Alberta, investors make decisions about when and where to build generation, and generators make offers to sell power into the market. A market operator ensures supply and demand are balanced in real time and the price of power is determined in a competitive wholesale market. An independent transmission operator is responsible for offering fair and open access to parties interested in using the transmission network. Local distribution companies (LDCs) are responsible for power distribution. Each of these parties has a different role to play in ensuring reliable power supply.

Most electricity service providers, whether they are vertically-integrated utilities or LDCs have a mandate to provide reliable electricity at the lowest practical cost. For bulk power systems, this requires planning for adequacy of supply in generation and transmission and then ensuring reliability in the operation of the system.

North American Electric Reliability Council (NERC)

For interconnected bulk power systems, NERC has made a key contribution to the development of industry reliability policies and standards.

NERC was formed in 1968 following the power blackout in Ontario and the U.S. Northeast in 1965. It is an industry organization that draws upon the technical expertise of its members NERC has ten regional councils, comprising about 140 control areas in Canada, the U.S. and the northern Baja region of Mexico.[12] Most Canadian electric utilities/system operators that have interconnections with other regions are members of NERC's regional councils.

NERC's stated mission "is to ensure that the bulk electric system in North America is reliable, adequate and secure." Toward that end, the organization develops planning standards and operating policies, which are the main methods it employs to achieve reliability. However, the standards and policies are voluntary, and are enforced by peer pressure.

NERC sets overall standards as a minimum, and its regional councils customize these to their unique circumstances, including local regulatory requirements. NERC also monitors and reports on "disturbances" on transmission interconnections, so that the knowledge and learning gained from such incidents can be shared with all NERC participants.

Planning standards address the longer term adequacy of generation and transmission infrastructure. NERC has adopted an industry planning standard for generation reserve margins based on a loss of load duration, on a probabilistic basis, of one day every 10 years. This typically results in capacity reserve margins in the range of 15-20 percent, depending on the region. A basic planning criterion for interconnected systems is the "n-1" criterion, which means that a transmission system is designed so that it can maintain service after the loss of the most critical

Operating Reliability

In addition to ensuring that adequate infrastructure is constructed and maintained, reliability depends on the essential activities of system operators and planners. Key activities include:

- observe and monitor the network to ensure power conditions, i.e., frequency, voltage, and power flows are correct;
- analyze and model the system to help plan operations and control uncertainties;
- communicate and coordinate with system controllers in other areas to maintain the integrity of the interconnected grid;
- take control actions, such as changing generation output, transmission switching, load shedding, to maintain operations within acceptable limits;
- monitor and enforce compliance to ensure all participants meet reliability requirements;
- make necessary improvements and additions to improve reliability and relieve constraints;
- ensure that market signals and incentives promote reliability-enhancing behaviour; and
- take appropriate actions to protect critical facilities, such as nuclear powerplants.

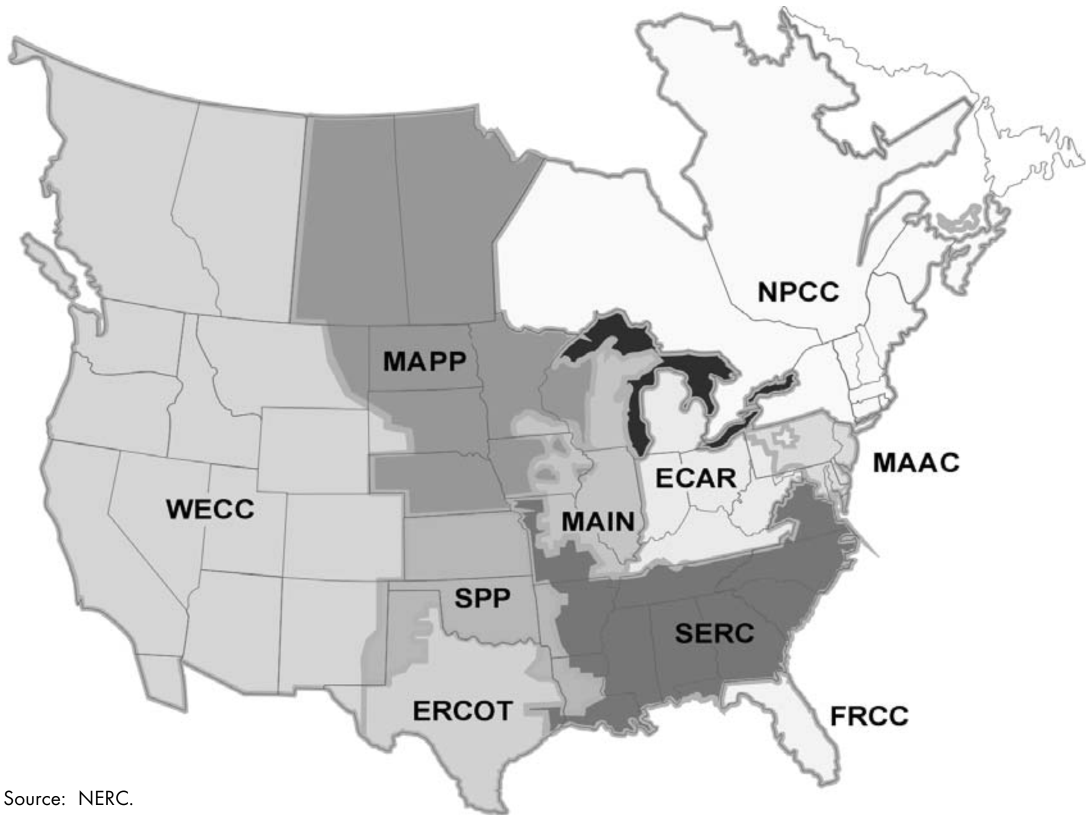
To successfully achieve many of the above activities requires that operators and planners have in-depth, ongoing training and sophisticated tools to deal with the complexity involved in operating electric grids.

Source: *Maintaining Reliability in a Competitive U.S. Electricity Industry*, Final Report of the Task Force on Electric System Reliability, September 29, 1998. Secretary of Energy Advisory Board, U.S. Department of Energy.

12 A control area is under the direction of one entity responsible for maintaining the balance between generation and load (demand) requirements, including coordination with adjacent control areas. There are currently 16 "reliability coordinators" responsible for ensuring this occurs.

F I G U R E 2 . 4

NERC Regions



Source: NERC.

unit in its infrastructure, such as a major generation facility or a major transmission line, without having to shed (or reduce) load.

Operating policies govern the real time operation of the grid and near term planning, and establish criteria for such functions as generation control and performance; system coordination; emergency operations, system maintenance, and training and certification of operating personnel.

2.4.2 The Provinces and Territories

Canada's electricity industry has evolved along provincial lines. Thus, the provinces and territories and their respective regulatory agencies have most of the regulatory oversight for reliability, although the extent of regulation and the mechanisms vary.

Most provinces have utilized NERC standards, either through the utilities under provincial regulation or in provincial legislation. Ontario, for example, has legislation making these requirements mandatory and empowers the IMO, with regulatory oversight by the Ontario Energy Board (OEB), to levy financial penalties for non-compliance with standards. Some provinces have their own specific standards, especially as they pertain to distribution systems. The Territories have no interconnections and few transmission lines. Thus, reliability problems tend to stem more from the reliance on single generation sources.

Under direction from the Council of Energy Ministers, federal, provincial, and territorial officials have been working cooperatively over the past several years on reliability and transmission issues. In August 2003, they prepared a report that examined a number of transmission investment opportunities in Canada, either to address transmission constraints or to support generation projects. The report concluded that the two most important barriers to transmission investment were project economics and market uncertainties, and that economic regulation was the third most important barrier. The report also concluded that new technologies, while they could diminish the need for new transmission investment, cannot be relied on to reduce transmission constraints.[13]

2.4.3 The Federal Government

The federal government is involved in electricity policy development in regard to interprovincial and international trade, including policies pertaining to electric reliability. The two main departments are Natural Resources Canada and the Department of Foreign Affairs and International Trade.

The NEB exercises the federal regulatory mandate with respect to the construction and operation of international power lines (IPLs) and electricity exports.[14] The NEB takes into account reliability when considering authorizations of power line and export applications.[15] It requires the applicant to provide information on the impacts of the operation of the proposed IPL on the power systems in other provinces, i.e., other than those provinces through which the line passes. Similar considerations apply in the authorization of exports.[16]

As part of its market monitoring function the NEB, in its long-term assessment of Canada's future energy supply and demand, includes a resource/load balance for the Canadian electricity sector. This analysis is undertaken in a total energy framework with input from industry experts and the public. The NEB's assessment of adequacy is from the standpoint of market monitoring, as it has no regulatory authority on that matter.

2.5 Mandatory Reliability Standards

The circumstances brought about by restructuring have been a driving force behind efforts to develop a system of mandatory reliability standards, which would be monitored and enforced through a compliance program with financial penalties. The Canadian Electricity Association, which represents Canada's electricity industry, supports mandatory standards. Additionally, some provinces have legislative and regulatory initiatives, in place now or planned, to support mandatory standards.

In the U.S., a proposal by NERC for mandatory standards includes regulatory oversight by the U.S. Federal Energy Regulatory Commission (FERC). The FERC is an independent agency within the U.S. Department of Energy that, among other responsibilities, regulates the transmission and wholesale sales of electricity in interstate commerce. The Energy Bill currently before the U.S. Congress also supports the development of mandatory standards, with the standards being developed by an Electric Reliability Organization (ERO). After the Energy Bill is passed, organizations may make submissions to the FERC for certification as the ERO, and the FERC will certify one organization.[17]

13 *Regional Electricity Transmission Grid Study*, Navigant Consulting, 2003.

14 The NEB Act also provides for the federal government to designate specific interprovincial power lines to be regulated by the NEB, but this provision has not been used.

15 Exports refer to exports across the international border.

16 These requirements are specified in the NEB Act and its Electricity Regulations.

17 Refer to H.R. 76, Electricity title.

The basic characteristics and functions of an ERO are:

- independent from market players;
- regulatory oversight by the FERC in the U.S.;
- to propose standards, which are approved by the FERC; and
- to enforce standards and levy fines for non-compliance, subject to FERC approval.

The Energy Bill calls for coordination with Canada and Mexico: "The President is urged to negotiate international agreements with the governments of Canada and Mexico to provide for effective compliance with reliability standards and the effectiveness of the ERO in the United States and Canada or Mexico."

The number one recommendation of the U.S.-Canada Power System Outage Task Force is that legislation should be enacted to make reliability standards mandatory and enforceable with penalties for non-compliance. The Task Force emphasizes the need for the ERO to be independent from market participants in setting and enforcing standards and in funding the operations of the organization. In contrast to the current arrangements where funding is provided by NERC members to NERC through the regional councils, the funding of the ERO would be provided from a regulated surcharge on transmission rates.

It is not currently known whether NERC (in a modified form) or another organization will constitute the ERO. Any organization may submit an application to FERC for certification. At the time of the writing of this report, the Energy Bill is still awaiting Congressional approval. In the interim, Congress has allocated additional funds to both the Department of Energy and FERC for reliability initiatives, and FERC has issued a policy statement, consistent with its existing authority, addressing the modification of NERC's reliability standards, compliance with standards and the recovery of reliability costs. The NERC Board of Trustees has also undertaken "to work closely with FERC and other applicable federal, state, and provincial regulatory authorities in the United States, Canada and Mexico to ensure that the public interest is met with respect to compliance with reliability standards."[18] This would include efforts toward improved compliance with NERC reliability standards and adopting the recommendations of the NERC Steering Group that investigated the 14 August 2003 blackout.

2.6 Summary

Electric reliability means that electric service will be delivered to consumers with a high degree of assurance. There are two basic aspects to electric reliability: planning for adequacy of generation and transmission infrastructure; and operational reliability, to ensure the system can withstand disturbances. The electric industry has developed numerous ways to measure reliability performance. Blackouts resulting from bulk system disruptions occur occasionally; most service disruptions to final consumers are the result of service disruptions at the distribution level. However, when disruptions on the bulk system do occur, they can have significant and widespread impacts.

System reliability can be enhanced through investment, technology and trade. In addition, there is now an increased interest in enhancing reliability from the demand side, for example, through development of demand response programs. In order for these programs to produce the intended effects, consumers must be exposed to the time-sensitive prices of electricity as an incentive to reduce consumption in periods of peak demand.

18 NERC Board of Trustees, 10 February 2004.

The electric industry, the provincial and territorial governments and their respective regulators, and the federal government have responsibilities to ensure reliability in Canada. Efforts by various parties are underway to develop a system of mandatory, enforceable reliability standards for the North American electric industry.

Provincial Frameworks

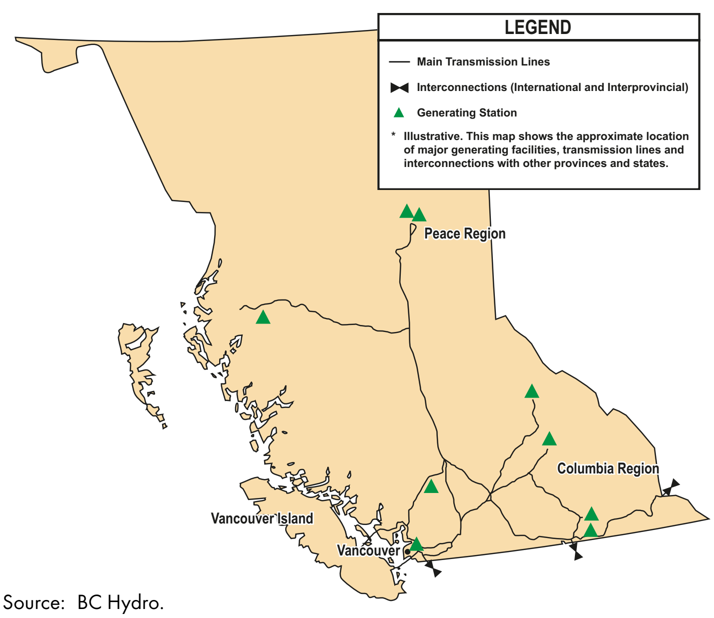
3.1 British Columbia

In November 2002, the Government of B.C. developed a long-term energy policy entitled *Energy for our Future: A Plan for B.C.* (Energy Plan). The Energy Plan's objectives are: to maintain low electricity rates and maintain public ownership of BC Hydro's core assets; have a secure, reliable energy supply; stimulate private investment; and have environmentally responsible energy development. A key element of the Energy Plan is the establishment of a heritage contract that locks in the value of existing low-cost generation and associated trade benefits for BC Hydro ratepayers. To position the electricity market for change, BC Hydro was unbundled into separate lines of business for generation and distribution and the transmission business was formed into an independent, Crown corporation called the British Columbia Transmission Corporation (BCTC).

BC Hydro serves 80 percent of B.C.'s domestic load and set a peak demand record of 9 619 MW in January 2004. Electric consumption is comprised of the industrial sector at 39 percent, the residential sector at 32 percent and the commercial sector at 29 percent. The next largest utility, Aquila Networks Canada (Aquila) has a current peak demand of 718 MW. The remainder of domestic demand is largely served by a number of municipal utilities and by industrial self-generation.

F I G U R E 3 . 1

B.C. Electric Transmission System



Source: BC Hydro.

B.C. currently has approximately 14 000 MW of generation of which BC Hydro owns 11 000 MW. The remainder is owned by Aquila, industrial generators and independent power producers. The provincial generation mix is 85 percent hydraulic with most of the remaining 15 percent thermal. Hydraulic resources are concentrated on the Peace River and Columbia River systems.

B.C.'s transmission grid consists of: BC Hydro's 18 000 km of power lines and 287 substations; Aquila's 1 700 km of power lines and ten substations; and the transmission systems of Alcan

Inc. and Teck Cominco Limited. For reliability planning and operation, BCTC and Aquila are members of the Western Electricity Coordinating Council (WECC)[19]. B.C. is connected to Alberta by two 138 kV lines and one 500 kV line and to the U.S. by two 230 kV and two 500 kV lines. The capacity for the Alberta interconnection is 1 200 MW of export and 1 000 MW of import. The capacity for the U.S. interconnection is 3 150 MW of export and 2 000 MW of import. However, the actual transfer capabilities of the interconnections are dependent on load levels, generation patterns and transmission elements in service.

3.1.1 Reliability Framework

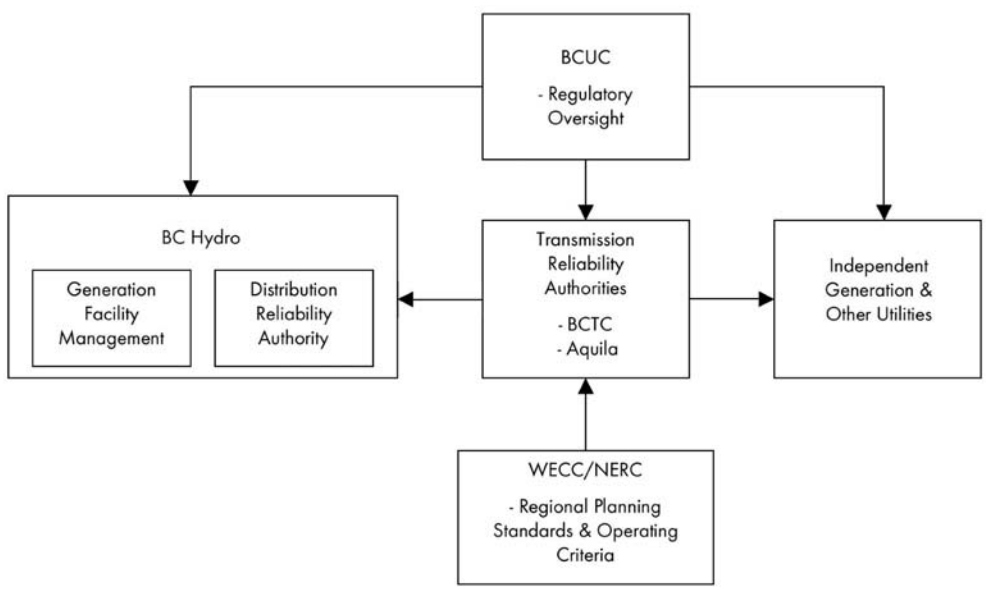
It is expected the Energy Plan will be fully implemented in 2004/2005. The B.C. Ministry of Energy and Mines (Ministry) has undertaken amendments to relevant legislation to put in place the necessary legal infrastructure, including the *Utilities Commission Act*, the *BC Hydro and Power Authority Act*, and the *Energy Efficiency Act*. In addition, the *BC Hydro Public Power Legacy and Heritage Contract Act* and the *Transmission Corporation Act* have been created to effect the required changes. With respect to regional electric reliability activities, the Ministry participates in the Committee on Regional Electric Power Cooperation[20] and as Class Five[21] members on the WECC.

British Columbia Utilities Commission (BCUC)

The BCUC ensures that utility rates are fair, just and reasonable and that utility operations are safe, adequate and secure. Utilities are required to provide the BCUC with long-term resource plans addressing adequacy and reliability of supply, among other objectives. The BCUC oversees independent generators through review of power purchase contracts with regulated utilities. It also

FIGURE 3.2

B.C. Reliability Framework



19 WECC is a regional council of NERC that is comprised of Alberta, B.C., all or portions of 14 U.S. states and the northern part of the Baja California Norte, Mexico.

20 The Committee on Regional Electric Power Cooperation is a sub-committee of the Western Governors' Association that focuses on electricity issues including reliability.

21 Class Five includes representatives from provinces and states that have policy or regulatory roles.

has authority to set standards, including reliability standards, for any regulated utility. Through recent decisions, the BCUC has supported the use of WECC/NERC planning and operating standards for B.C.'s transmission systems. It monitors reliability performance through complaint investigations, utility status reports and WECC compliance reports. Aquila is regulated using a performance-based ratemaking system which includes assessment of reliability targets that are set and reviewed annually. There is interest in moving in the same direction with BC Hydro.

BC Transmission Corporation

BCTC is responsible for transmission system planning, operating and managing approximately 90 percent of the provincial grid. Since BC Hydro retains ownership of the facilities, there are formal agreements between BCTC and BC Hydro governing the relationship.

BCTC's objectives are to provide open access to transmission, to promote the development of efficient electricity markets in B.C. and to effectively participate in wider regional markets. For long-term planning, BCTC works with BC Hydro and others to determine whether system enhancements are required in order to meet forecasted needs.

From the standpoint of operating reliability, functions include reserve management, voltage control and outage planning and coordination. As a reliability authority, BCTC sets targets for system performance, including the supply system component of SAIFI and SAIDI and an asset health risk index.

The provincial transmission grid in B.C. is considered a control area within WECC. As such, BCTC plans and operates the system in compliance with WECC reliability standards and operating criteria. BCTC also belongs to the WECC Reliability Management System.[22] This program requires signatories to observe certain operating reliability criteria and contains sanctions for non-performance, such as financial penalties. In addition, BCTC is a member of the Northwest Power Pool,[23] which coordinates regional contingency reserve sharing. Because of its interconnections, BCTC can reduce its capacity reserves[24] by up to 400 MW.

BC Hydro

The role of BC Hydro Generation is mainly to operate, maintain and upgrade existing facilities. To maintain and improve the condition of generation assets, BC Hydro plans to invest one percent of total system replacement costs annually for the next ten years.

BC Hydro Distribution is responsible for acquiring supply, on a least-cost basis, to meet domestic demand along with operating, maintaining and upgrading its distribution system. Along with other distribution utilities, BC Hydro must submit an Integrated Electricity Plan (IEP) to BCUC identifying how it intends to meet future demand. The IEP contains a supply/demand outlook, resource options and an action plan that includes the consideration of both generation and transmission solutions to ensure that the most economic resources are available to meet forecasted demands.

22 The Reliability Management System was implemented in 1999 as a voluntary program of WECC.

23 The Northwest Power Pool is a voluntary organization promoting cooperation among its members to achieve reliable operation of the interconnected electric power system and coordinate system and transmission planning.

24 Capacity reserves are required to allow a system to withstand temporary outages of generating units. In B.C., capacity reserves of approximately 14 percent of dependable supply capacity are maintained.

Independent Power Producers

Most independent power producers supply electricity to BC Hydro exclusively through power purchase contracts. To encourage reliable generation, some contracts have explicit expectations of capacity and energy delivery. For example, the current call for tenders of new generation proposals for Vancouver Island capacity require 97 percent availability during the winter months, and includes financial penalties for poor performance.

Large Consumers

BC Hydro offers a load curtailment service that allows industrial customers to reduce their energy costs through load-shifting activities while allowing BC Hydro to curtail specified loads when needed. Additionally, BC Hydro is required by the Energy Plan to introduce “stepped rates” where escalating rate tiers will result in large industrial customers paying higher rates as consumption levels increase. Such a rate structure should send price signals that could reduce demand over the longer term.

3.1.2 Reliability Issues

Generation Adequacy

Energy planning ensures that sufficient generation resources are available to satisfy annual energy requirements. Capacity planning ensures that sufficient generation capacity is available to serve the annual peak demand and avoid loss of firm load after contingencies. Depending on a number of factors, both energy and capacity shortfalls are forecasted to occur during the period 2006 to 2013. An additional planning consideration is the Government’s direction that distributors, including BC Hydro, pursue a voluntary goal of acquiring 50 percent of new supply from “clean”[25] electricity sources over the next ten years. Another balancing option is B.C.’s interconnections. These allow the use of imports which, at times, are more economic than drawing down reservoir levels or increasing thermal generation.

BC Hydro is currently addressing growing demand through the following initiatives: the Power Smart program (demand-side management); the Resource Smart program (existing generation restoration); requests for new generation projects involving green energy or customer-based generation; and new capacity on Vancouver Island. Additionally, until 2007, imports will be considered an important element of economically accomplishing the system’s energy balance. In a recent filing of its IEP, BC Hydro states that it intends to undertake a review to determine optimum timing for possible new capacity additions at the Revelstoke and Mica hydro facilities.

In accordance with the Energy Plan, BC Hydro will purchase electricity from the private sector, which is expected to provide new generation resources. It is likely that independent power producers will build generation if profitable long-term purchase agreements can be made. The multitude of objectives and stakeholders in BC Hydro’s resource acquisition process could impact the ability to schedule new generation most effectively. As such, depending on the timing, BC Hydro may be forced to rely on imports for a time, which could be more costly than domestic production.

Although most energy or capacity shortages can be reliably dealt with through imported supply, some locations, such as in the case of Vancouver Island, are subject to facility limitations. A Vancouver Island capacity shortfall is expected as early as 2007/2008 due to growing demand and the expected

25 Clean energy sources include: wind, solar, tidal, wave, geothermal, fuel cells, micro-hydro, co-generation and fuels that are not fossil-based (e.g., hydrogen).

retirement of a high voltage DC transmission line from the mainland. BC Hydro is currently considering its options for increasing Vancouver Island capacity. However, until capacity is increased, electric reliability on Vancouver Island may be compromised if contingencies occur that limit the ability to transport power from the mainland. As contingency options, a new 230 kV AC submarine transmission line as well as a life extension of the high voltage DC transmission line are under consideration.

Transmission

BCTC faces system reliability challenges consistent with the nature and age of the transmission system. Increased trade volumes and issues arising from wholesale market complexity require interconnections to function at the highest level possible. Given load growth requirements, and to avoid transmission becoming a bottleneck to new generation development, a pre-build approach to new facilities is being considered. Additionally, there will be efforts to ensure system adequacy for the 2010 winter Olympics.

A benefit of having a flexible hydraulic system is the ability to engage in trade by importing electricity when prices are low and exporting electricity when prices are high. Beyond the economic benefits, access to imports is essential when contingencies impacting system stability and reliability occur. To maintain interconnection benefits, B.C. must remain attuned to maintaining the integrity of the regional transmission grid and to evolving U.S. wholesale electricity market rules.

WECC currently provides a basis for planning and reliable operation of the interconnected regional grid. Efforts to form a new regional transmission organization called RTO West are underway by several western utilities, including BCTC. A key consideration in determining B.C.'s participation in the RTO is the maintenance of provincial sovereignty, and legal and operational jurisdiction. If RTO West becomes operational, and Government of B.C. decides to participate, BCTC would work with RTO West to ensure the seamless coordination of imports and exports along with joint planning of upgrades. BCUC would continue to have regulatory oversight over BCTC's activities including the conditions of joining the RTO.

3.1.3 Summary

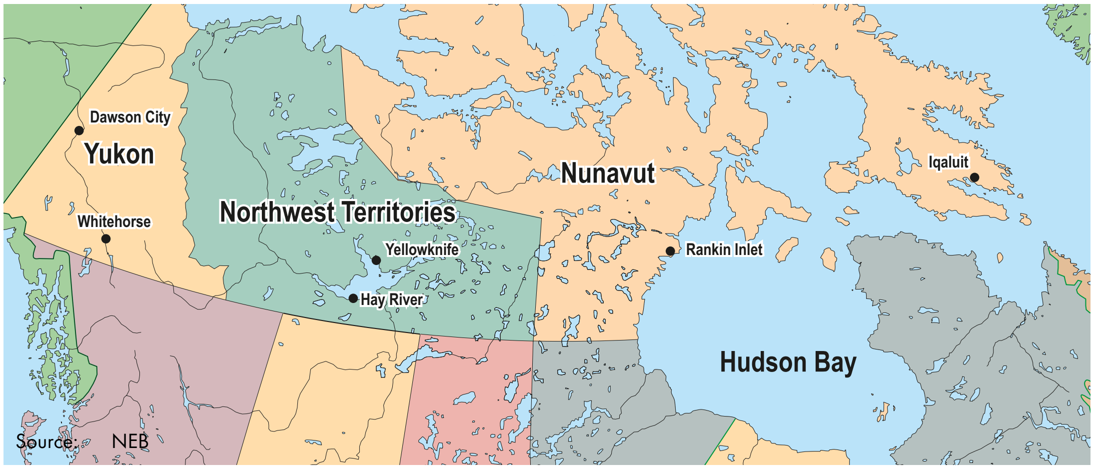
The Government of B.C. has implemented a new Energy Plan and electricity market structure which includes the unbundling of the transmission business from BC Hydro. While the Government and the BCUC will provide direction and oversight respectively, BCTC will plan, operate and manage the transmission grid to ensure reliability among other objectives. Along with maintaining existing heritage generation assets, BC Hydro will be responsible for resource acquisition to meet demand growth. According to the Energy Plan, the private sector will be responsible for supplying new generation resources for future needs. BC Hydro is completing an IEP to identify its approach to meeting future supply requirements. BCTC is dealing with issues of optimizing interconnections, aging facilities and effective participation in regional trade organizations.

3.2 Yukon, Northwest Territories and Nunavut

The territories cover 40 percent of the Canadian land mass. However, with a population of about 102 000 - of which 31 000 reside in the Yukon, 42 000 in the Northwest Territories (NWT) and 29 000 in Nunavut - there is a very low population density. Therefore, apart from the transmission systems that serve more concentrated loads in the Yukon and NWT, there are many isolated communities that rely on diesel-fired generation plants and local distribution networks.

FIGURE 3.3

Yukon, Northwest Territories and Nunavut



3.2.1 Yukon Territory

In 2002 generation in the Yukon was 313 GW.h, of which 88 percent originated from hydro sources and the remainder from diesel-fired generation units. Installed generation capacity was about 130 MW, of which hydro accounted for 75 MW and diesel 55 MW; wind capacity was less than one MW.

Yukon Energy Corporation (YEC), a subsidiary of the Crown-owned Yukon Development Corporation, is the dominant power generator with almost 90 percent of capacity, including all the hydro facilities. It also owns and operates two separate transmission systems that serve loads in the vicinity of Whitehorse-Aishinik-Faro and Dawson City-Mayo. The remaining generation capacity, in smaller communities, is owned and operated by Yukon Electric Company Limited (YECL), a subsidiary of ATCO Electric. Outside the Dawson City area, YECL handles most of the distribution in the Yukon and in some places distributes power as a wholesale customer of YEC.

Electricity generation and distribution are subject to oversight by the Yukon Utilities Board under the *Public Utilities Act of the Yukon*. Under this Act, companies are required to file with the Utilities Board quarterly and annual reliability performance reports pertaining to the frequency and duration of customer power outages. In addition to monitoring reliability performance, this information is used internally for benchmarking with other utilities.

Cost savings and some improvement in reliability have been achieved by the recent completion of the Mayo-Dawson City transmission line. Current reliability issues stem from having to respond to outage situations in isolated communities, and the cost of replacing aging diesel units.

3.2.2 Northwest Territories (NWT)

In 2002 electricity generation in the NWT was 552 GW.h, of which about 57 percent was produced by utility operations and the remainder from mining and oil and gas operations, the latter either for direct use in these industries or sales to others. Fifty-one percent of total generation originated from hydro sources, 29 percent from diesel-fired units and 20 percent from natural gas-fired units.

The Northwest Territories Power Corporation (NTPC), a Crown corporation of the Government of the Northwest Territories, is the main producer of electric power in the NWT. Power is produced from 27 systems including six hydro facilities and two separate transmission systems located near

Hay River and Yellowknife. Power is produced from natural gas-fired facilities in Inuvik and Norman Wells and diesel-fired facilities in other communities. Power distribution is handled by two separate distribution companies (subsidiaries of ATCO Electric) in the Hay River and Yellowknife areas and four other isolated communities. NTPC looks after distribution in the remainder of the territory.

Under the *Northwest Territories Power Corporation Act* it is the responsibility of the NTPC to generate, transmit and distribute power in the territory "on a safe, economic, efficient and reliable basis."[26] The NTPC is regulated by the Public Utilities Board of the NWT and is required to file information on reliability performance, specifically on customer outage information.

In remote communities, a reserve margin of 5-10 percent is required to account for normal demand variations. Additionally, a reserve margin large enough to compensate for the loss of the largest generating unit during the system peak must be available. Apart from the ongoing challenge of ensuring reliable service to remote communities, an important issue is the accommodation of potential demand growth that would result from the construction of a natural gas pipeline down the Mackenzie Valley corridor.

3.2.3 Nunavut

In 1999, Nunavut was created by the division of the Northwest Territories into two territories. In April 2001, Nunavut Power Corporation (NPC) assumed the eastern operations of NTPC, after the two territorial governments agreed to divide the assets and liabilities of NTPC and establish two new corporate entities. Since then, NPC has become a subsidiary of Qulliq Energy Corporation, a territorial Crown corporation with headquarters in Iqaluit.

NPC provides electricity for 25 communities, either on the coast or with near access to the coast. Power is produced by diesel-fired facilities, which require that fuel be supplied by coastal shipping. The operations of the NPC come under the *Qulliq Energy Corporation Act* and applications for capital expenditures and rate review are subject to the advice of the Utility Rates Review Council.

Reliability issues stem from the lack of a road network, which makes it difficult to respond to supply contingencies, i.e., in those cases where back-up generation is not available or requires access for activation. Ensuring adequacy of supply is an ongoing concern due to the recent and expected high rate of population growth, with the attendant impact on growth in electricity demand.

3.2.4 Summary

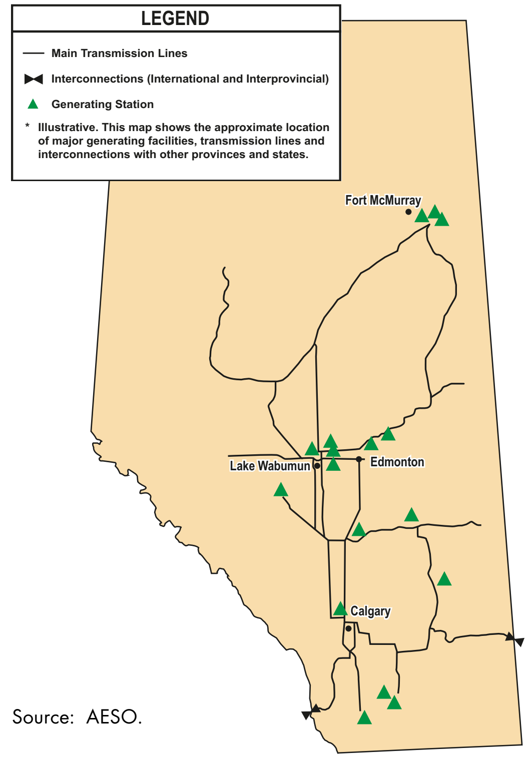
The territories have no interconnections with each other, and they do not have any interconnections with the provinces or the U.S. Thus the entities engaged in power production and transmission are not members of the North American Electric Reliability Council. A unique aspect of ensuring reliability is the relatively high portion of load served in isolated communities, which rely on single sources of supply.

26 Northwest Territories Power Corporation, 2003 Annual Report, P. 5.

3.3 Alberta

FIGURE 3.4

Alberta Electric Transmission System



Source: AESO.

The electricity industry is in a state of evolution as the Government of Alberta continues its efforts to restructure by introducing competition in the generation and retail sectors while keeping the transmission and distribution sectors regulated monopolies. Currently, the wholesale electricity market is competitive while the retail sector should be fully restructured by 2006.

Electric load growth has been strong for the past several years reflecting Alberta's economy. A peak demand record was set in the winter of 2003/2004 at 8 967 MW. Electric consumption is led by the industrial sector at 59 percent, the commercial sector at 23 percent, and the residential and farm sectors at 18 percent. Based on a forecasted average annual increase of two percent, peak demand could be as high as 11 506 MW by 2013.

Alberta has nearly 11 194 MW[27] of installed generation capacity. The approximate generation fuel mix is 49 percent coal, 38 percent gas, eight percent hydraulic and five percent "other." Since 1998, 2 918 MW of new generation has been commissioned, almost all of which is gas-fired. Of the total generation capacity, 68 percent is owned by formerly regulated utilities while the remaining 32 percent is owned by the industrial sector and independent power producers. Future generation projects are focused on three regions: co-generation near Fort McMurray, coal near Lake Wabumun and wind in southern Alberta.

The transmission system consists of 22 322 km of power lines and 510 substations. In general, northern Alberta is rich in generation while the south has a generation deficit, requiring a transfer of energy from north to south. The Alberta transmission system is part of the Western Interconnection and for reliability planning and operations is a member of the WECC. Alberta is connected to the rest of the Western Interconnection through B.C. and to the Eastern Interconnection through Saskatchewan. The interconnection with B.C. consists of one 500 kV line and two 138 kV lines with a capacity of 1 200 MW for imports and 1 000 MW for exports. However, the available transfer capability (ATC) ranges from zero to 715 MW for imports and from zero to 700 MW for exports based on system load and operating conditions, including any congestion on the Edmonton to Calgary corridor. The Saskatchewan interconnection consists of a 230 kV transmission line with a 150 MW DC link. The ATC for the Saskatchewan interconnection varies between zero and 150 MW based on load and operating conditions.

3.3.1 Reliability Framework

The Government of Alberta, the Alberta Electric System Operator (AESO) and the Alberta Energy and Utilities Board (EUB), fulfill key roles in providing direction, transmission grid management and

27 Capacity includes the City of Medicine Hat.

industry oversight respectively for the wholesale marketplace. The owners of generation, transmission and distribution complete the essential tasks of operating, maintaining and upgrading facilities to ensure safe and reliable operations.

The *Electric Utilities Act* establishes the broad framework for the electric industry. Key aspects related to reliability functions are identified for the AESO, the EUB and facility owners. The Government, specifically Alberta Energy, is responsible for providing a market framework that ensures Albertans receive long-term reliable supplies of competitively priced electricity. Accordingly, Alberta Energy determines the overall policies and direction with corresponding adjustments to legislation, such as the amendment, in 2003, to the *Electric Utilities Act* to clarify and enhance the roles of industry bodies that support a competitive marketplace. In December 2003, a Transmission Development Policy (Transmission Policy) was put in place to promote sustainable transmission development, with new regulations expected in 2004. Alberta Energy will continue to monitor developments in the electric industry in conjunction with the AESO and EUB to determine if "course corrections" are required.

Alberta Energy and Utilities Board

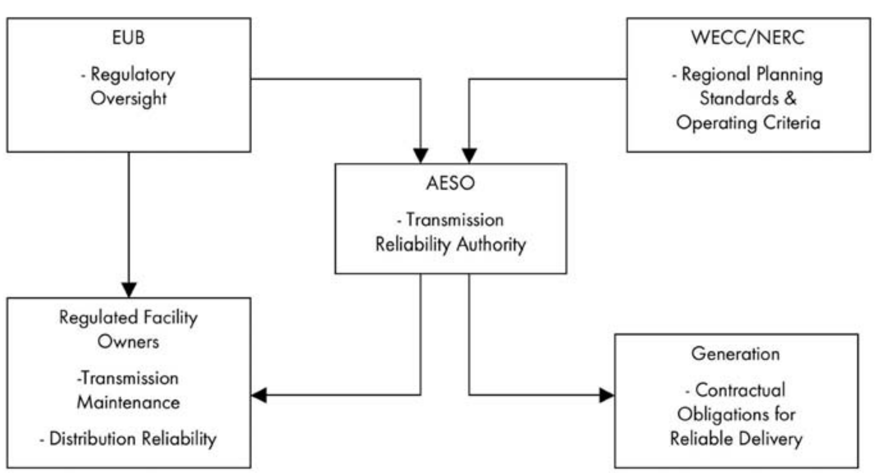
The EUB's electricity mandate is two-fold: to ensure the safe, responsible and efficient development of generation and transmission facilities; and to ensure distribution utilities and the AESO provide safe and reliable service at just and reasonable rates. The EUB considers generation and transmission development proposals through a public hearing process and provides a decision approving, modifying or rejecting the proposal. Reliability performance measures and reporting requirements have been established for distribution companies while generation and transmission companies are required to report any major outages. Finally, in response to public complaints, the EUB may review the operating practices and procedures of the regulated transmission and distribution companies to ensure compliance with appropriate reliability approaches.

Alberta Electric System Operator

The AESO is responsible for transmission system control, planning, system access, power pool operations and load settlement. The AESO has distinct duties and responsibilities that address system reliability. The AESO conducts long-term system planning to forecast the needs of market participants, and to develop transmission plans that enable efficient, reliable and non-discriminatory system access and provide timely implementation of required system expansions and enhancements.

FIGURE 3.5

Alberta Reliability Framework



From an operational reliability standpoint, the AESO's short-term system operation and control function incorporates a number of activities such as operating reserve procurement and management, voltage control and outage planning and scheduling. In carrying out its reliability functions, the AESO works with generation, transmission and distribution owners on matters such as interconnection operations, maintenance programs and/or schedules, and potential upgrades (e.g., new substations) to the transmission system.

Alberta is considered a control area within WECC. Several members of the WECC, including the AESO, belong to the Northwest Power Pool, which coordinates regional contingency reserve sharing. Furthermore, Alberta is a signatory to the WECC Reliability Management System Agreement, which requires compliance with reliability standards and contains sanctions for non-compliance. The AESO's current planning criteria align with WECC's standards for guidance while considering provincial needs.

Facility Owners

Generation, transmission and distribution owners are responsible for completing the essential tasks of operating, maintaining and upgrading facilities to ensure safe and reliable operations. To encourage reliable generation, contractual obligations in electricity purchase agreements are likely to contain delivery expectations along with identified penalties for non-performance. The *Electric Utilities Act* also requires transmission and distribution owners to ensure the safe, reliable and economic delivery of electricity.

Large Consumers

There are no formal provincial programs for shaping electrical loads to assist in system reliability efforts. However, because a market price signal exists, some large consumers reduce power consumption (generally up to 300 MW) when prices become sufficiently high. Because price spikes generally occur when the supply/demand balance is tight, timely demand reductions can contribute to the reliability of the overall system.

Another method some consumers use to ensure electric reliability is to generate their own power. Some industries, such as oil sands production, incur large costs if they experience service curtailments or reductions in power quality. In several cases, companies have built co-generation facilities to reduce the risk of relying exclusively on the provincial grid while concurrently benefiting from increased revenues from the sale of excess electricity.

3.3.2 Reliability Issues

Of the many challenges in the restructuring market, the most relevant to maintaining reliability in the mid to long-term are transmission capacity and market sustainability.

Transmission Capacity

In recent years, investment in transmission facilities has not kept pace with growing electricity demand and generation investment. From 1985 to 2003, peak demand grew by approximately 4 000 MW; however there were no major upgrades made to the transmission system. Since 1998, about 3 000 MW of new generation have been added with proposals for an additional 2 500 MW. As a result of demand and generation growth, congestion has begun to occur in certain areas of the transmission grid. Current and future transmission challenges include: capacity constraints in the regions of Fort McMurray, northwestern Alberta and southwestern Alberta; transfer capability on the provincial interconnections; and capacity constraints from northern to southern Alberta. As early as 2005, the corridor between Edmonton and Calgary is expected to experience increasing congestion. The AESO intends to implement interim measures to ease the transmission capacity constraints affecting north to south power transfers to defer the need for new facilities to 2009.

In recent years, a number of regional upgrades to the Alberta grid have been completed. Preliminary estimates indicate that $1.5 billion in additional transmission investments are required to meet the goals set by the Transmission Policy. The Transmission Policy states that transmission should be reinforced to the point where 95 percent of expected economic wholesale transactions can occur without any congestion and that interconnections should be able to import and export power in accordance with their design capability under normal conditions.

Congestion and lack of capacity on the transmission system can act as a barrier to timely generation development and can impact reliable system operations. While transmission upgrades are essential, there are divergent views on the scale and timing of additional capacity requirements. Basic issues revolve around the specific purpose, the amounts required and the costs. Detailed route determinations and environmental assessments are additional considerations which take considerable time.

Long-Term Market Sustainability

Prior to restructuring, the method of stimulating generation investments was through a regulated rate of return, which allowed an investor to build a facility with little risk of unprofitable operation. Now, investors must forecast whether adequate revenues can be expected over the life of the facility to recover costs and earn a return on investment. Many investors prefer to minimize risk through long-term purchase contracts for electricity to provide predictable revenues. Nonetheless, in the current Alberta marketplace, retailers and distribution companies have not generally been committing to new long-term arrangements. One barrier to increasing long-term purchase contracts is the significant credit requirement. Another barrier is that a number of power buyers already have long-term power purchase arrangements in place.

Lacking long-term purchase arrangements, investors become exposed to the risk of unpredictable revenues. A prolonged period of high prices may be required to give them the confidence that new generation will produce adequate returns. However, prolonged high price periods have severe consequences on industrial, commercial and residential markets prompting public outcry with a potential political response. Investors can become even more reluctant if government intervention further decreases their ability to forecast the long-term sustainability of new generation.

A lack of investor confidence could lead to a prolonged generation shortage resulting in system reliability being compromised. Although Alberta has numerous generation proposals for the near term, new generation is required in the mid to long-term: to maintain appropriate reserve margins; to replace aging and obsolete generation; and to meet growing demand. Because such a long lead time is required to build new generation with supporting transmission infrastructure, this issue requires resolution in the near term. Alberta Energy, the AESO and the Market Surveillance Administrator[28] are assessing the situation and will conduct policy discussions and development with industry stakeholders during 2004.

28 The mandate of the Market Surveillance Administrator is to oversee the operation of a fair, efficient and openly competitive electricity market in Alberta.

3.3.3 Summary

Many organizations play a role in ensuring that electricity is reliably transported from generators to consumers. The Government and the EUB provide direction and industry oversight respectively, while the AESO is the transmission grid operator, system planner and reliability authority. In addition, facility owners are responsible for the essential tasks of operating, maintaining and upgrading their systems to ensure safe and reliable operations.

In recent years, the electricity market has been characterized by steady load growth, dramatic increases in generation investment and modest transmission investments. In response to growing system congestion, a transmission policy has been put in place to encourage system development. In order to continue to attract an appropriate level of generation investment, a means to address long-term market predictability is under consideration.

3.4 Saskatchewan

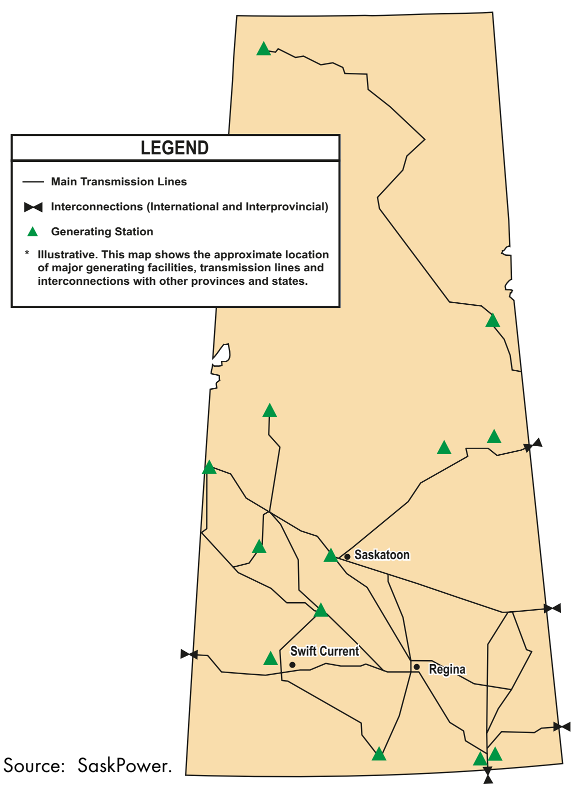
Saskatchewan Power Corporation (SaskPower or the Corporation) is a Crown corporation owned by the Province of Saskatchewan. SaskPower is the principal electricity supplier in Saskatchewan and a vertically-integrated utility that provides generation, transmission, and distribution services. SaskPower offers open access and has established an open access transmission tariff (OATT) so it complies with FERC reciprocity requirements. This enables suppliers outside of Saskatchewan, municipal utilities in Saskatoon and Swift Current, and independent power producers connected to the grid to access the transmission system to transport electricity to wholesale customers within Saskatchewan or across the province to other jurisdictions. Neither the Corporation nor the Province has plans to further restructure the market.

Approximately 17 percent of the province's energy needs are met by electricity. The industrial sector demands more than half of the electricity generated in the province, while the commercial and residential sectors each use approximately 25 percent of the province's electricity. Saskatchewan's peak electric demand in 2002 was 2 800 MW.

SaskPower operates 15 generating facilities with an installed capacity of approximately 3 000 MW. The system includes four base-load thermal stations, seven hydro stations, three peaking stations, and a wind power facility. Fossil generation supplies about 70 percent of the electricity produced by SaskPower, with most of the remainder coming from hydroelectric power. SaskPower also obtains an additional 500 MW of power from joint ventures and long-term power purchase agreements.

FIGURE 3.6

Saskatchewan Electric Transmission System



Source: SaskPower.

SaskPower manages 12 026 kilometres of transmission line (i.e., 72 kV or higher). Saskatchewan is asynchronously connected to Alberta by a 230 kV direct current line with a design transfer capability of 150 MW. A 110 kV double circuit line and three 230 kV lines connect to Manitoba. The total transfer capability is 550 MW from Saskatchewan to Manitoba and 525 MW from Manitoba to Saskatchewan. One 230 kV line connects to North Dakota with a capability of 165 MW from North Dakota to Saskatchewan and 215 MW from Saskatchewan to North Dakota. The capabilities from Manitoba and North Dakota are interdependent, and cannot be fully used simultaneously. Saskatchewan is at the tail end of the Mid-Continent Area Power Pool (MAPP) region (which includes Manitoba to the east and several states to the south) so it is not greatly impacted by disturbances in the MAPP region.

3.4.1 Reliability Framework

Saskatchewan does not have a provincial regulator to oversee the utility's operations. However, SaskPower is governed by the *Power Corporation Act* and is subject to the provisions of the *Crown Corporations Act*. This Act gives to the Crown Investments Corporation (CIC) broad powers to set the direction of SaskPower. The *Power Corporation Act* authorizes the Corporation to implement appropriate standards, rules or guidelines with respect to the operation, planning, and design of its generation or transmission facilities within an integrated regional power grid. The Corporation is also empowered to acquire and maintain membership in an integrated regional power organization.

Where required by legislative policy directive, SaskPower submits performance management and investment decisions for review and approval by the CIC and the provincial Cabinet. Regulatory oversight is governed by two bodies: the Saskatchewan Rate Review Panel provides an independent review and recommendation on bundled electricity rates (which are approved by Cabinet); and an OATT customer dialogue group deals with issues associated with transmission rates and tariffs. This group of stakeholders includes Saskatchewan Industry and Resources, members of industry, and groups that could choose an alternate supplier (although none have actually chosen an alternate supplier). According to a new governance structure that was announced in September 2003, the Corporation reports to a Minister specifically responsible for SaskPower, rather than the Minister responsible for the CIC. An independent Board of Directors continues to provide transparency and oversight for the Corporation.

SaskPower sets its reliability standards internally and reports annually to MAPP regarding the NERC compliance program. SaskPower follows industry practice when determining its level of generation reserves, and informally participates in MAPP, currently on a voluntary basis. SaskPower has decided to formally adopt NERC standards and participate in transmission reliability bodies. Reliability measures are reported in the SaskPower Balanced Scorecard section of its Annual Report.

SaskPower is responsible for all aspects of reliability for the integrated system. It undertakes long-term planning and produces 10-year forecasts for generation and transmission adequacy. SaskPower has an ongoing process to upgrade its control centre, its software, and the technologies used to control generation and the entire interconnected system. Reliability of day-to-day operations is promoted through training and adherence to established standards, and the corporation has detailed response plans to deal with major system disturbances.

3.4.2 Reliability Issues

When planning its system to ensure future energy needs would be met, SaskPower had the option of installing generation and/or building up transmission networks that would enable trade. Saskatchewan installed additional generating capacity so the province now has an abundance of available power.

Although power is abundant, SaskPower experiences occasional problems with generation sources. While sufficient generation reserves are established to ensure a high degree of reliability, Saskatchewan benefits from interties which enhance reliability and allow economic trade. Since SaskPower is part of an interconnected network, it is able to rely on the larger system to provide adequate power for some of its needs. As a result, customers are largely unaffected by potential disruptions. This makes it beneficial for Saskatchewan to continue to be part of the larger interconnected power grid.

Saskatchewan also benefits from seasonal trade and has excess power available for export. To maintain its ability to trade in the U.S., SaskPower has complied with FERC requirements for open access. Regional Transmission Organizations (RTOs), such as the Midwest Independent Transmission System Operator, Inc. (MISO) in the U.S., have integrated both commercial and reliability aspects of the transmission system in a fashion that does not align with Saskatchewan's needs. This creates seams issues and uncertainty for SaskPower in determining an appropriate participation in the bulk electric system. SaskPower is assessing options to ensure appropriate participation in meeting the regional reliability and NERC requirements.

Approximately two years ago SaskPower began an internal review of reliability. In February 2004 SaskPower's Board of Directors approved an approach to align the corporation with NERC's standards. Accordingly, SaskPower will establish itself as a NERC-certified Reliability Authority and plans to join the Midwest Reliability Organization (which is expected to replace MAPP) as it emerges as the new regional reliability council.

3.4.3 Summary

Saskatchewan has enough generation to meet its own peak demand in a reliable fashion, and benefits from the interconnected grid from both an economic and reliability perspective. SaskPower has its own reliability standards to govern the system; however, it has determined that an independent demonstration of industry-accepted reliability standards, such as compliance with NERC standards, has become a significant business issue. SaskPower's objectives with respect to reliability are to ensure reliable day-to-day operations, to ensure long-term planning is appropriate, and to determine the appropriate role for it to play within the larger interconnected system.

3.5 Manitoba

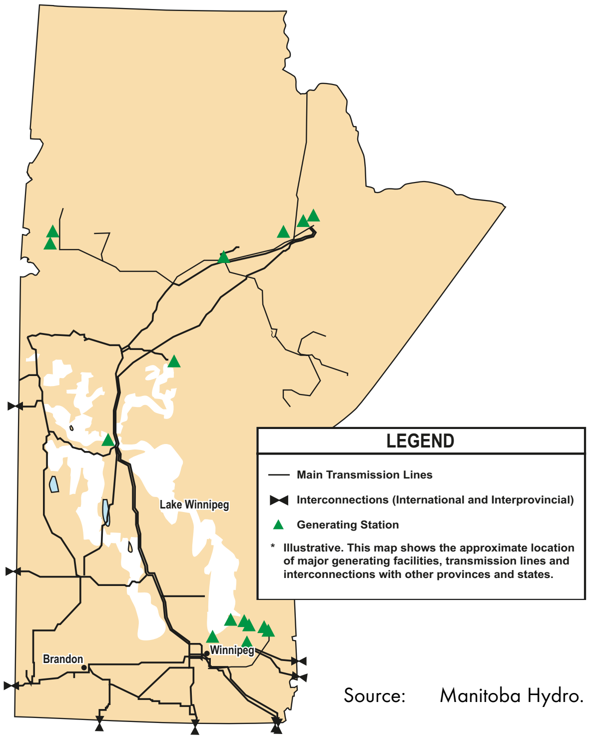
Manitoba Hydro is a Crown corporation and the sole provider of electricity service in Manitoba. The vertically-integrated utility provides generation, transmission and distribution throughout the province. The retail electricity rates charged by the corporation are subject to regulatory review by the Public Utilities Board. Manitoba Hydro offers open access transmission service and is functionally unbundled (i.e., transmission is operated independently from the other functions) but has no plans for further restructuring.

Approximately 24 percent of the province's energy needs are met by electricity. The residential and industrial sectors each use about 40 percent of the electricity generated in the province, while the commercial sector uses approximately 20 percent of the province's electricity. Manitoba's record-setting peak electric demand in 2003 was 3 916 MW.

Manitoba's installed capacity is about 5 475 MW. Approximately 95 percent of its power is generated at 14 hydroelectric facilities. The remaining five percent comes from thermal generation and alternative energy sources. The system was designed so Manitoba can meet its power needs even in

FIGURE 3.7

Manitoba Electric Transmission System



Source: Manitoba Hydro.

an extremely poor water year. As a result, when water conditions are normal, Manitoba Hydro has excess hydro-generated power available for export.

Manitoba Hydro manages 9 293 kilometres of transmission line and eleven interconnections. A 110 kV double circuit radial line and three 230 kV lines connect to Saskatchewan. The total transfer capability on the three 230 kV lines from Manitoba to Saskatchewan is 525 MW and the total transfer capability from Saskatchewan to Manitoba is 550 MW. Manitoba and Ontario are interconnected via two 230 kV power lines and a non-synchronous 115 kV power line. The maximum transfer is 300 MW. One 500 kV line and three 230 kV lines connect to the U.S. with a nominal capability of 2 175 MW, although the import capability is just 900 MW.

Manitoba is a control area within MAPP. The MAPP region also includes Saskatchewan to the west and several states to the south. Manitoba Hydro has interconnection agreements with adjacent systems, the system planners meet on an annual basis, and there is generally a "good neighbour" policy concerning actions taken by one system operator that have the potential to affect adjoining systems.

3.5.1 Reliability Framework

The corporation is governed by the *Manitoba Hydro Act*, and this Act's express purpose is to "provide for the continuance of a supply of power adequate for the needs of the province..." Manitoba Hydro is required to engage in and promote economy and efficiency in the development, generation, transmission, distribution, supply, and end-use of power. An independent Board appointed by order of the Lieutenant Governor in Council has the power to carry out the functions and duties specified in the Act. The Act gives Manitoba Hydro the ability to set, coordinate and enforce standards and rules, for the security, reliability and quality control of interconnected transmission and distribution lines. Manitoba Hydro is responsible for ensuring all aspects of electric reliability including system planning and operations of generation, transmission, and distribution. As a member of MAPP, Manitoba Hydro participates in the MAPP Generation Reserve Sharing Pool, and is a member of the MAPP Regional Reliability Council which is a NERC region. As such, Manitoba Hydro is bound to comply with NERC and MAPP operating and planning standards and is subject to the regional compliance assessment program.

In September 2001, Manitoba Hydro signed a Coordination Agreement with MISO and became the first province to participate in an RTO. However, unlike U.S. transmission-owning members of MISO, Manitoba Hydro has not transferred operational control of its transmission facilities to MISO. Pursuant to the Coordination Agreement, Manitoba Hydro purchases Reliability Coordination services and tariff administration services from MISO. The parties also agree to coordinate congestion management procedures and to coordinate transmission service pricing so as to eliminate the seam between the Manitoba and MISO tariff regions. In providing Reliability Coordination services, MISO monitors key facilities and provides advice to Manitoba Hydro on corrective actions when needed. MISO deals with problems outside of the Manitoba Hydro system, for example, by initiating transmission relief procedures on interfaces affecting Manitoba Hydro's operations. Efficiencies and costs savings can be realized when providing reliability functions because the power grid is so interconnected, and because there are so many players.

Long-term planning is carried out by Manitoba Hydro and coordinated with MISO. Manitoba Hydro also supplies transmission planning information to MAPP, and MAPP uses this information along with data from other utilities to produce long-term regional transmission expansion and reinforcement plans. Manitoba Hydro is also responsible for connection of generation facilities to the Manitoba Hydro transmission system.

In order to ensure cost-effective generation expansion plans, Manitoba Hydro employs demand-side management, load curtailment and supply-side efficiency programs. For example, the utility offers a discount to large consumers who are able to curtail their power use when required. Manitoba Hydro also has a Power Smart[29] program, which encourages consumers to use less power. The power saved by this program can be exported in the short term, which increases revenues and lowers domestic rates. In the long run, the power saved reduces the need for new facilities. The Power Smart program has subsequently been incorporated into a larger Provincial Government energy development initiative.

3.5.2 Reliability Issues

As shown in Figure 3.5, the bulk of Manitoba's generation is situated in the northern part of the province while much of the load is located in the southern part of the province. Two transmission lines, which currently carry 70 percent of the power produced in Manitoba, are routed on a common right-of-way on the west side of Lake Winnipeg. These lines carry power generated in the north to areas of demand in the south part of the province. This poses a potential reliability threat since one event could take both lines out of service. For example, extreme weather, such as an ice storm, could impact both lines. Manitoba Hydro is evaluating new generation options, and is considering building a new line which would also run north to south. However, it would run along the east side of Lake Winnipeg, well away from the existing lines.

Manitoba normally exports more than 30 percent of the power it generates. However, in 2003 poor water conditions led to Manitoba Hydro being a net importer of power. Manitoba Hydro needs reliable access to other power systems so it can trade energy in a large marketplace and obtain the best price possible for its energy exports and imports. Obtaining open access on U.S. transmission systems requires Manitoba Hydro to provide transmission service on similar terms and conditions where it is capable of doing so. As NERC and MAPP reliability standards change, Manitoba Hydro, as a member of MAPP, is contractually obligated to implement such changes. Therefore, Manitoba Hydro diligently monitors and participates in U.S. reliability and operating organizations and monitors developments in regional reliability, market issues and transmission services.

29 More information on this program can be found at Manitoba Hydro's website: www.hydro.mb.ca.

3.5.3 Summary

As a vertically-integrated utility, Manitoba Hydro will continue to be responsible for reliability in the province. Interconnection agreements and participation in MAPP and MISO will dictate greatly how reliability concerns with the interconnected system are addressed. While Manitoba benefits from its RTO participation it also faces challenges to meet its requirements, maintain open access and ensure that its unique interests are addressed through participation in the U.S. organizations.

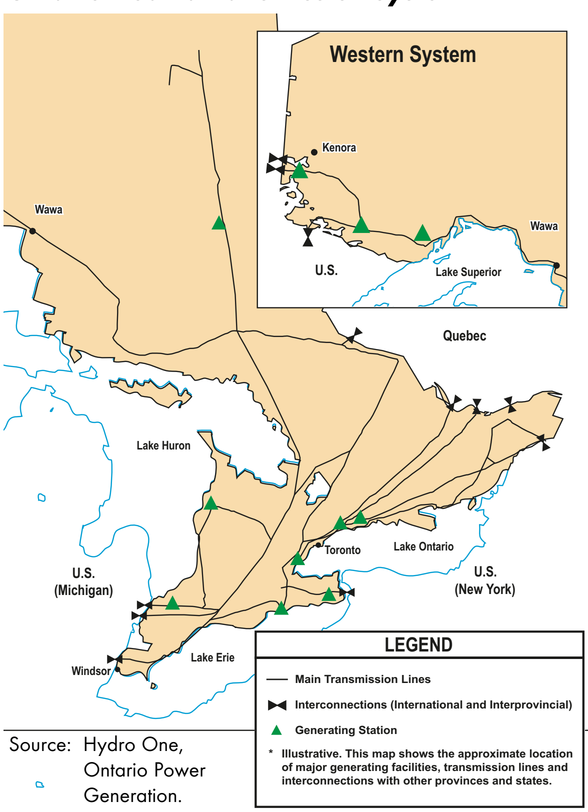
3.6 Ontario

With the opening of the Ontario electricity market on 1 May 2002, Ontario completed the transition from a traditional industry structure, dominated by a single vertically-integrated utility, Ontario Hydro, to an unbundled industry, with clear corporate separation between generation, transmission and distribution. The operation of the wholesale spot market, where prices are set by market forces, and the operation of the transmission grid are overseen by the Independent Electricity Market Operator (IMO). The IMO and all electricity market participants (generators, transmitters, distributors, wholesalers and retailers), are subject to regulatory oversight by the Ontario Energy Board (OEB).

The unbundled structure provides direct access to the Ontario wholesale electricity market by generators and bulk power buyers, the latter mainly including the distribution utilities and large industrial customers. Sellers and buyers from adjacent interconnected provinces and states can also participate in this market. Hydro One, which owns and operates about 97 percent of the Ontario transmission grid under the direction of the IMO, also serves as the largest distribution company, serving many rural customers and various communities.[30]

FIGURE 3.8

Ontario Electric Transmission System



Source: Hydro One, Ontario Power Generation.

The Ontario market also enables competition at the retail level, whereby retailers are allowed access to the distribution-connected customers and can enter into electricity commodity sales contracts, with varying terms and conditions. With the retail price cap invoked in November 2002 and modified in November 2003, competition at the retail level was to a large extent eliminated, and several retailers have exited the market (at least temporarily). Large volume customers continue to negotiate prices directly with generators or power marketers, or to purchase at the spot market price. The OEB has been directed by the Government to develop new pricing mechanisms to be implemented no later than 1 May 2005.

30 Other licensed transmission companies are Great Lakes Power, Canadian Niagara Power (Fortis), Cat Lake Power and Five Nations Energy.

Electricity accounts for 18 percent of end-use energy demand in Ontario at 139 TW.h, which is divided about equally among the residential (33 percent), commercial (33 percent) and industrial (34 percent) sectors.

Demand varies on a seasonal basis, higher during the winter and summer and lower in the spring and fall. The peak in January 2004 of nearly 25 000 MW was about the same as the summer peak in the July/August period.[31] Generation capacity in January 2004 was 30 400 MW and comprised of a diverse mix of nuclear (36 percent), hydro (25 percent), coal (25 percent), gas and oil (13 percent) and other sources such as wind and geothermal (less than one percent). Capacity is subject to real-time reductions of about 2 500 MW from planned outages and other factors such as allowances for hydroelectric generation below rated capacity.[32]

The market is supplied by a 29 000 km transmission system. This includes a network of 500 kV, 230 kV and 115 kV power lines in central and southern Ontario and 230 kV and 115 kV power lines in the northwestern part of the province, extending to the Manitoba border and Minnesota.

Interconnections with neighbouring provinces and states have enabled Ontario entities to engage in trade, optimize construction and utilization of generation, and enhance the reliability of the Ontario transmission grid. Import transfer capability is in the range of 4 000 - 5 300 MW in the summer and 4 700 - 5 500 MW in the winter. Export capability is 4 000 - 4 600 MW in summer and 4 500 - 5 900 MW in winter. The largest transfer capabilities are with Michigan, New York and Québec, followed by Manitoba and Minnesota.[33]

3.6.1 Reliability Framework

Providing electric reliability in Ontario is the responsibility of the IMO, with regulatory oversight provided by the Ontario Energy Board.

The Independent Electricity Market Operator (IMO)

Legislation designating responsibility for reliability is contained in the *Electricity Act, 1998*, which empowers the IMO to make and enforce the Market Rules.[34] "The objectives of the Market Rules are to govern the IMO-controlled grid and to establish and govern efficient, competitive and reliable markets for the wholesale sale and purchase of electricity and ancillary services in Ontario."[35] The Market Rules specify the roles and responsibilities of the IMO and market participants toward achieving these objectives.

The IMO schedules electricity transactions on the Ontario grid and monitors activity on the interties to maintain load/resource balances. Specific functions include directing generators, transmitters and distributors to adjust their operations to changing conditions, as required, to ensure efficient operation of the market and to ensure reliable operation of the integrated power system. From an operational reliability standpoint, activity in adjacent regions, or control areas, is conveyed via direct

31 IMO Facts and Figures: Record peak demand was 25 414 MW on 13 August 2002, and the record winter peak was 24 937 MW on 15 January 2004.

32 This excludes three nuclear generation units at Pickering A and two units at Bruce A.

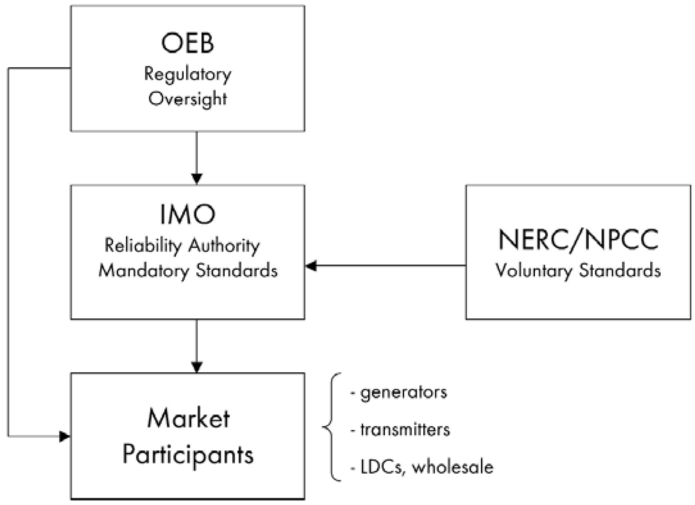
33 IMO, Ontario Transmission System, March 2003, Table 5.2.

34 *Electricity Act, 1998*, subsection 32(1). This Act provides the framework for Ontario's competitive electricity market.

35 Market Rules, Independent Electricity Market Operator, P. 1-2.

FIGURE 3.9

Ontario Reliability Framework



communications with control area operators and via the NERC reliability coordinator.[36]

As a participant in the Northeast Power Coordinating Council (NPCC), the IMO is responsible for ensuring compliance with NPCC standards. Although the standards are voluntary, they are mandatory in Ontario and a condition of market participation. The IMO has signed an NPCC participation agreement that requires adherence to NPCC standards.[37]

Reliability Compliance Program

The requirements of market participants to maintain reliable grid operations are contained in the Market Rules and compliance to these requirements is addressed by the IMO's Reliability Compliance Program. The program "provides the procedures for monitoring and measuring the extent to which reliability standards are being adhered to, for detecting reliability non-compliance and for planning, conducting and enforcing corrective measures to remedy non-compliance."[38] Information obtained from the program serves as the basis of reporting to the NPCC, which oversees compliance in the North American northeast.[39]

The market participants are subject to sanctions by the IMO for not abiding by reliability standards and the Market Rules generally. The IMO is empowered to levy financial penalties for non-compliance.

In 2002, the IMO was the subject of two audits by NPCC/NERC. The NPCC Compliance Monitoring and Assessment Sub-Committee noted that "the Ontario Area compliance program is unique in that is directly tied to market rules and licensing requirements," and encouraged other areas to adopt this approach.[40]

Reliability Outlooks

Based on information from the compliance program the IMO monitors the state of the Ontario grid, on a near-term and longer-term basis and publishes reports on its analyses. Two such reports are the 18-month and 10-year reliability outlooks. These reports assess the adequacy of generation and

36 This function is described in Chapter 2.

37 Although these standards may be called voluntary, Ontario's interconnection with neighbouring Canadian and U.S. jurisdictions is conditional on these standards being adopted for use in Ontario.

38 IMO Market Manual, Part 7.9.

39 IMO Market Manual, Part 7.9 and Market Manual, Part 7.5.

40 IMO submission to the U.S.-Canada Power System Outage Task Force, 8 December 2003.

transmission and may serve as a guide for market participants in investment decisions. These reports also assist NERC/NPCC in undertaking reliability assessments for the NPCC region.[41]

Based on its market monitoring, the IMO may request Hydro One and other transmission companies under its jurisdiction to submit proposals to the OEB to build transmission facilities. However, in exceptional circumstances, the IMO may go further and direct companies to submit proposals to the OEB.

The Ontario Energy Board (OEB)

The OEB derives its regulatory authority from the *Ontario Energy Board Act*, *1998* and the Electricity Act, 1998. The OEB regulates the provincial transmission system and all local distribution companies (LDCs). It is also responsible for ensuring that transmitters and distributors meet their obligations to connect and serve their customers. The OEB is responsible for issuing licences to participants in the Ontario electricity market, including the IMO. The Board has the authority to impose penalties of up to $20,000 per day for a participant who is in contravention of their licence.

With regulatory oversight for transmission, the OEB is authorized to: approve "just and reasonable" rates; decide on applications to construct facilities; and require companies to submit performance information with respect to reliability. As the regulator of distribution, the OEB monitors reliability performance for electricity distributors and requires the reporting of various indicators on customer outages (SAIDI, SAIFI, CAIDI). This information may be used in setting or approving rates, and in ensuring that licensed distributors are operating their networks reliably.

Consumption-Based Programs

Two recent reports examine the opportunities associated with DSM and DR programs. As part of a mandate "to develop an action plan for attracting new generation, promoting conservation and enhancing reliability of the transmission grid," the government-appointed Electricity Conservation and Supply Task Force (ECSTF) acknowledged two mechanisms that enable wholesale consumers to respond to price signals in the IMO-administered market. It also acknowledged the IMO's pilot program for economic demand response. The ECSTF stated that demand response for retail customers may take longer to implement, because of the number of consumers and the need to aggregate sufficient reduction in demand, and because of the need to install new metering technology. The ECSTF estimated that significant reductions in peak demand could be achieved in Ontario, with attendant price benefits, by the creation of a "conservation culture" and the promotion of technologies and appropriate rates to facilitate time-of-use demand shifting.[42]

On 1 March 2004, the OEB published a report containing its recommendations.[43] This was in response to the Minister of Energy's June 2003 directive to consult with stakeholders toward identifying and reviewing options for the delivery of DSM and DR programs in the electricity sector. The report recommended that a conservation agency oversee DSM and DR activities, including: developing a province-wide plan; monitoring and evaluating programs; and providing annual reports to the Minister. The OEB would license the conservation agency and conservation efforts and programs would be funded by a charge on electricity consumption.

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41 The IMO website, www.theimo.com, contains comprehensive market monitoring, in addition to the information provided in these reports, such as background information on the operation of the grid and the IMO-Administered Market (e.g., bulk power prices).

42 *Tough Choices: Addressing Ontario's Power Needs*, Electricity Conservation and Supply Task Force, January 2004.

43 *Demand-Side Management and Demand Response in the Ontario Energy Sectors*, Report of the Board to the Minister of Energy, March 1, 2004.

3.6.2 Reliability Issues

On 14 August 2003, Ontario along with adjacent U.S. states experienced a region-wide blackout. Normal operations on the Ontario grid were restored over the next several days under the direction of the IMO and cooperation of market participants.[44] In response to a general call to the public by the IMO to conserve energy, the Ontario and federal governments curtailed operations, by reducing "non-essential" services during that period. Industry was requested to voluntarily reduce consumption by 50 percent.

Although service was restored relatively quickly to most users, there was significant inconvenience and costs borne by the public and industry, as the result of initial power loss and the subsequent conservation efforts. One industry group, for example, estimated its losses conservatively at about $20-30 million. Another sample of large power users suggests that the total cost was well over $100 million. The Final Report on the August 14, 2003 Blackout states that manufacturing shipments in Ontario were down $2.3 billion dollars. The power users have called for a restoration protocol that would recognize the varying capabilities of industries to reduce load and shift load between plants to satisfy their reduction requirement. This would result in lower overall costs to industry, and possibly make it easier for the available, constrained generation to balance load during the restoration period.

Over the past decade, industrial power consumers in Ontario have experienced increased demand for power quality, i.e., power with minimal interruptions and voltage fluctuations. This results from the increased use of sensitive electrically-driven equipment and electronic process controls, and reflects trends also evident in the residential sector and office buildings. Even brief interruptions can be very costly in some processes. Demands for improved service are expected to continue.

In its market assessments, the IMO monitors potential issues that have reliability implications. In its December 2003 18-month report the IMO addressed the reliability implications of closing the 1 200 MW coal-fired Lakeview Generating Station in April 2005. Reliability impacts include potential load loss and/or unacceptable low voltage levels in the Greater Toronto Area. After a number of transmission and generation alternatives had been considered, Hydro One made an application to the OEB for expedited approval to build a transmission substation in the Greater Toronto Area in order to mitigate these reliability concerns. In the longer term, generation will also be required in the Toronto area.[45]

While a solution has been proposed and acted on in this case, the concern has been expressed that timely and efficient investments in generation and transmission may not always be the outcome as long as no single entity is charged with the responsibility for system planning. The ECSTF addressed this matter in recommending that Hydro One be assigned the responsibility to issue an annual plan for transmission development, through consultation and within an integrated planning framework to be developed by the IMO.[46]

In its March 2004 10-year outlook, the IMO identified significant challenges for Ontario's electricity system over the next decade. A severe shortfall is possible due to uncertainty surrounding the Pickering A nuclear units return to service, the lack of new generation and the commitment to shut down 7 500 MW of coal fired generation. Reactivation of nuclear capacity and the addition of new

44 IMO website, www.theimo.com: Restoration of Service, Sequence of Events.

45 IMO 10-year outlook, March 2004.

46 ECSTF Report, P.76.

gas-fired generation have eased concerns for the next 18 months; however, more resources are required every year during the next 10 years. The ECSTF recommended a diversity of supply options should be considered, and that coal-fired plants may need to be kept in operation until other supply options and conservation obviate the need for coal generation.

The Ministry of Energy's Plan for the Electricity Sector

On 15 April 2004, the Ontario Ministry of Energy announced a plan for major changes to the Ontario electricity market.[47] The intent of the plan is to encourage the development of new reliable supply, promote a culture of conservation, lessen the environmental footprint of electricity undertakings, and promote stability in electricity prices for small consumers while enabling large consumers to benefit from competitive markets. Major initiatives include:

- creation of the Ontario Power Authority, which would be obligated to ensure long-term supply adequacy in Ontario through developing and implementing an integrated system plan for conservation, generation and transmission;
- creation of a Conservation Secretariat, within the Ontario Power Authority, to lead Ontario's conservation efforts and monitor progress;
- establishment of targets for conservation, renewable energy and the overall supply mix of electricity in Ontario (targets set by the Ministry of Energy), with the Ontario Power Authority charged with achieving them;
- price regulation of OPG's nuclear and baseload hydroelectric assets by the OEB, while the prices for other generation would continue to be set by the market; and
- price stability for residential and small business consumers, while preserving the flexibility for all consumers to purchase their electricity through the market.

The government stated that it intended to introduce legislation in June 2004 and, following a period of study and evaluation, pass legislation in the fall.

3.6.3 Summary

Ontario has mandatory reliability standards that are included in the IMO's market rules. Implementation includes a comprehensive compliance program with an explicit statement of expectations and identification of remedies when standards are not met. Ongoing market monitoring, notably by the IMO's regularly published reliability assessments, provides a basis for identifying challenges and investment opportunities. There is concern about generation adequacy in the near term and longer term. To address the demand side of the market, the government-appointed ECSTF and the OEB have recently undertaken two major initiatives assessing DSM and DR.

In April 2004 the Ministry of Energy announced a plan for the Ontario electricity sector. The intent of this plan to lead to the development of reliable electricity supplies, encourage conservation and improve the performance of the market.

47 *Choosing What Works for A Change*, Notes for remarks by the Honourable Dwight Duncan, Minister of Energy for Ontario, 15 April 2004.

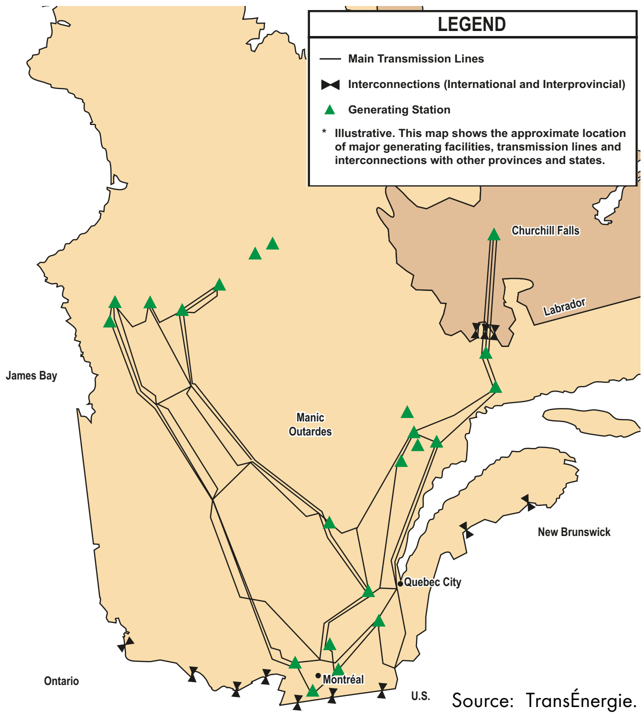
3.7 Québec

As the principal generator, transmission owner and distributor in Québec, Hydro-Québec (HQ) operates as a regulated (for transmission and distribution), functionally unbundled utility. While wholesale access is allowed, HQ has exclusive rights for distribution except in a few municipalities. HQ is composed of four functional divisions: HQ Production, HQ TransÉnergie, HQ Distribution and HQ Équipement.

Electricity accounts for about 40 percent of provincial energy demand. The residential and commercial sectors account for approximately 50 percent of electricity consumption, and the remaining 50 percent occurs in the industrial sector. A relatively large percentage of heating load in Québec is electric. On 15 January 2004, Québec registered an unprecedented peak demand of 36 279 MW.

FIGURE 3.10

Québec Electric Transmission System



Source: TransÉnergie.

HQ's total installed capacity at year-end 2002 was 32 660 MW. In addition to the installed capacity of its own generating facilities, HQ has access to most of the output from the Churchill Falls hydro power complex (situated in Labrador), which has a rated capacity of 5 428 MW, and the output from 133 wind turbines at the Matane and Cap-Chat wind farms (100 MW capacity). Generation is predominantly hydro-based and is mostly concentrated in and around the James Bay and the North Shore regions. There is also a relatively small amount of gas-fired and nuclear generation.

HQ's system at year-end 2002 totalled 32 314 km of transmission lines with voltage varying from 49 kV to 765 kV, and 505 substations. Each of the transmission lines from James Bay and the Manic-Outardes Complex covers a distance of more than 1 000 km to reach major load centres in southern Québec. HQ's transmission network also includes 15 interconnections with neighbouring systems (Table 3.1). Distribution lines within Québec total over 105 705 km.

TABLE 3.1

Québec Interconnection Transfer Capability (MW)

	From Québec	To Québec
Labrador	0	5 200
New Brunswick	1 215	785
Ontario	1 295	670
New England	2 305	1 870
New York	2 125	1 000

Québec is a part of the NPCC, and is interconnected with the NPCC primarily by DC ties.[48] While Ontario and many states in the U.S. Northeast were impacted by the 14 August 2003 blackout, Québec's grid was largely unaffected. According to the Final Report on the August 14, 2003 Blackout, "the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less rapidly. Therefore, the electricity system in Québec was not affected by the outage, except for a small portion of the province's load that is directly connected to Ontario by AC transmission lines."[49] The Final Report also pointed out that, although DC ties can act as buffers between systems, they do not allow instantaneous generation support following the unanticipated loss of a generating unit.

3.7.1 Reliability Framework

The *Act Respecting the Régie de l'énergie* defines the following roles for the industry and provincial regulator: "The electric power carrier shall establish operating standards and technical requirements, including standards of reliability for its electric power transmission system, and submit them to the Régie for approval." Within the Act, "the electric power carrier" is defined as HQ TransÉnergie.

The Régie keeps itself abreast of reliability developments affecting the NPCC as a non-voting NPCC member. The Act specifies that the Régie may impose a financial penalty (maximum $50,000) on the electric power carrier or distributor if they violate certain provisions of the Act. In assessing capital projects the Régie incorporates reliability considerations. The Régie does not set reliability standards but monitors performance indicators, including service quality.

TransÉnergie, the transmission division of HQ, assumes three basic functions: System Operator-Transmission (Reliability Authority), Load and Generation Balancing (Balancing Authority) and System Operator - Interconnection (Interchange Authority). TransÉnergie acts as the Reliability Authority (RA) in the province since it owns and operates the province's bulk electric system. HQ implemented a functional separation between TransÉnergie and its merchant function in 1997, and at the same time, implemented an internal standard of conduct to ensure that the RA will act first and foremost in the interest of the overall reliability of the control area/interconnection before any merchant interest of purchasing/selling entities.

As a full, voting member of NPCC, TransÉnergie participates in the NERC and NPCC standards setting. According to a NERC Audit Report on TransÉnergie released in 2002, "TransÉnergie complies with reliability standards identical to, and in some cases more stringent than, NERC and NPCC requirements." For example, to maintain operational reliability, Québec system operators must resolve operating security limit violations within 15 minutes, which is more stringent than the NERC or NPCC 30-minute standard. The RA has the authority to take actions in case of emergency. TransÉnergie uses the "one day in 10 year" outage criterion for transmission planning.

In a recent decision, the Régie determined that it could not approve, as requested by TransÉnergie, the set of NERC/NPCC documents submitted by TransÉnergie. The Régie stated that it was generally satisfied with TransÉnergie's planning and design standards for its transmission system, but the fact that TransÉnergie made reference to the NERC and NPCC requirements placed the application outside the Régie's regulatory oversight.

48 Although it is generally considered part of North America's Eastern Interconnection, the large AC power system within Québec is isolated from other portions of the interconnection via DC ties. These ties act like a firewall in a communications network. Due to its geography and nature, Québec's power system has historically been more susceptible to electrical disruption as a consequence of natural events and challenging operational situations. By connecting its system to others' exclusively through DC ties, Québec can effectively isolate its system while at the same time remaining part of - and participating in - the Eastern Interconnection.

49 Final Report on the August 15, 2003 Blackout, p. 102.

The SAIDI statistics reported by TransÉnergie have been lower than the target of 6.5 hours per year, averaging 0.51 over the period 1998-2002. SAIDI measures the average hours of service interruption per customer due to power failures or scheduled outages on the transmission system, not including exceptional events such as the ice storm of January 1998. TransÉnergie also reports on the NERC indicators for measuring power frequency compliance and for measuring how well generation and load are balanced in the control area. Both indicators reveal that TransÉnergie exceeds the NERC minimum threshold levels.

As the predominant distributor of electric power in Québec, HQ Distribution has the "obligation to serve" all electric power customers in Québec, i.e., it is responsible for ensuring that consumer needs are met. To fulfill this obligation, HQ Distribution develops short-term and long-term (10 years or more) load projections and makes any necessary supply arrangements with HQ Generation as well as other generating entities to ensure it has sufficient power and energy to meet load requirements. HQ Production is not regulated, but has a legislated mandate to provide a "heritage pool" of 165 TW.h/year at 2.79 cents/kW.h.

HQ Distribution is required to initiate a competitive bidding process for any additional load requirements. It is also responsible for developing DSM programs, which need to be approved by the Régie. HQ Distribution is continuing its direct involvement in energy efficiency through its Energy Efficiency Plan 2003-2006. With an objective of 750 GW.h in energy savings by 2007, the Plan will require investments of $257 million over the next three years.

HQ's Strategic Plan 2004-2008 stated HQ Production will maintain a sufficient energy reserve to cover a 64 TW.h runoff deficit over two consecutive years. It will also maintain a 10 to 12 percent energy reserve margin for the heritage pool, equivalent to a load-shedding risk of 2.4 hours per year.

3.7.2 Reliability Issues

Québec's electric power system has two key characteristics: a predominantly hydro-based generation and an extensive long-distance transmission network. Furthermore, operations are conducted under severe winter conditions. This poses particular challenges associated with reliability management. For example, HQ must ensure it has contingency plans (e.g., import capability) to meet its firm load requirements in case of sustained low hydraulic conditions.

As a significant importer, trader and exporter of power in Eastern Canada and in the U.S. Northeast, Québec relies on accessible and reliable neighbouring transmission systems to optimize its operations and profitability. Reliability has become an even more important issue as trading activity has increased. In recent interconnection agreements reached with neighbouring systems, reliability was a key element.

Another issue relates to system planning. Before restructuring, HQ was the central planner and its vertically-integrated structure facilitated internal coordination and information sharing. As the utility becomes a functionally unbundled entity, system planning presents new challenges due to some key market uncertainties. For example, new generation must be chosen by HQ Distribution through a competitive bidding process and therefore, is difficult to predict.

The fact that the 14 August 2003 Blackout did not affect Québec reveals some advantages of a system that is asynchronous to its neighbouring systems. However, as mentioned earlier, the trade-off is that such systems do not allow instantaneous generation support following a major system disturbance.

In its Strategic Plan 2004-2008, HQ projected a relatively tight supply/demand balance by 2006-2007. This projection has generated significant public interest. The Government of Québec has asked the Régie to examine new generation capacity requirements to 2010, alternative generation options, as well as the potential contribution of energy conservation to ensure adequacy of power supply in the province. The Régie has until 30 June 2004 to submit its findings.

3.7.3 Summary

Hydro-Québec, mainly through its divisions HQ TransÉnergie and HQ Distribution, is the principal entity responsible for reliability in Québec. The Régie regulates the transmission and distribution activities. It has a mandate for approving reliability standards and provides regulatory oversight for reliability aspects and performance of TransÉnergie and HQ Distribution. Consumers typically rely almost exclusively on HQ to ensure their electricity requirements are met when needed. The existence of a provincial regulatory body provides a forum for market participants to voice and seek to address their concerns, especially as they relate to service quality and reliability.

3.8 New Brunswick

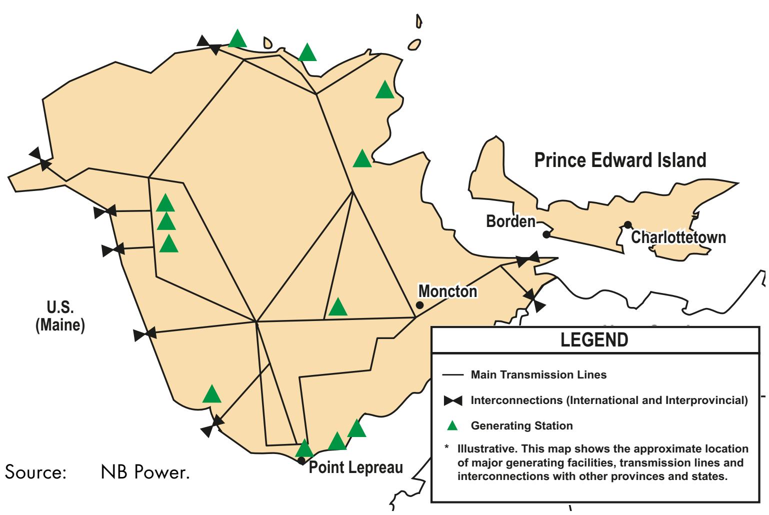
The electricity market in New Brunswick is evolving from a monopoly structure to a competitive environment for wholesale and large industrial customers. Under the provisions of the new Electricity Act (Act), NB Power Corporation will be restructured into NB Power Holding Corporation with four operating subsidiaries (Nuclear, Generation, Transmission and Distribution). The Act also mandates a new, independent entity, the System Operator, to direct the operation of the transmission system and to establish and enforce market rules. The new market structure is scheduled to be implemented on 1 October2004.

Electricity accounts for about 24 percent of provincial end-use energy demand. Total electricity demand is composed of 46 percent industrial, 17 percent commercial and 36 percent residential. Peak demand has increased in recent years, reaching 3 333 MW in January 2004. Generation is diversified, with nuclear power accounting for about one-third of the electricity generated in the province; hydropower supplies about 19 percent and fossil fuel generation the balance. New Brunswick is the principal electricity supplier to Prince Edward Island (P.E.I.) and northern Maine, and also exchanges power with adjacent jurisdictions.

The province's network includes 6 700 km of transmission and 26 500 km of distribution lines. It has interconnections with P.E.I., Québec, Nova Scotia and Maine. Total transfer capability out of the province amounts to 2 377 MW compared to 1 719 MW for imports.

FIGURE 3.11

New Brunswick Electric Transmission System and Prince Edward Island



Source: NB Power.

TABLE 3.2

New Brunswick Interconnection Transfer Capability (MW)

	From New Brunswick	To New Brunswick
Nova Scotia	550	350
P.E.I.	222	0
Québec	785	1 215
Maine	820	154

The major international power line, with interconnection at Orrington (Maine), has an export transfer capacity of 700 MW. Two smaller interconnections totalling 120 MW of transfer capacity serve isolated loads in northern Maine. The NB Power Energy Control Centre administers the system operations including dispatching, load balancing and transmission system access.

In March 2003, NB Power received approval from the Board of Commissioners of Public Utilities (PUB) to implement an OATT to provide non-discriminatory access to generators and consumers inside and outside the province. The tariff will be managed by the System Operator and provide revenue to allow New Brunswick Power Transmission Corporation to operate and maintain the transmission system. The tariff was designed to be consistent with the FERC requirements in the U.S.

3.8.1 Reliability Framework

The PUB has responsibility over NB Power operations, electricity rates and major capital investment projects. The provincial Cabinet can make a final decision based on the PUB's recommendations or can overrule a decision made by the regulator. Currently, there is no legislated requirement for NB Power to report to the PUB on reliability performance.

As a Crown corporation, NB Power is mandated to provide adequate supply to customers in the province. The utility is a voting member of the NPCC, participates in its standard setting process and adheres to NPCC reliability standards. The utility is also subject to compliance audits and has to meet NPCC reporting requirements.

NB Power assumes a planning function in cooperation with other market participants under the current regime. The main criterion used for long-term generation planning is the "one day in 10 year outage" criterion, which corresponds to an equivalent of a 20 percent reserve margin requirement. For transmission, the main criterion used is the first contingency limit (n-1). For operations, the utility must meet NPCC's obligation of having enough generation to cover the first contingency (loss of the largest unit) within 10 minutes, plus 50 percent of the second contingency within 30 minutes. Part of this obligation is met through interconnection agreements with Nova Scotia, P.E.I., and northern Maine which are part of the Maritime Control Area within NPCC.

The company uses reliability measures as internal planning tools. For generation, reported measures include unit availability indices, such as the percentage of time, including planned and unplanned outages, a station is available to generate electricity. For transmission and distribution, SAIDI and SAIFI are used, respectively. NB Power stated in its Annual Report 2002-2003 that overall reliability performance remained strong, but was affected by province-wide lightning storms in the summer 2002 and a localized ice storm in the winter 2002-2003.

The Act provides an overall reliability mandate to the System Operator. The market rules will establish a capacity requirement that ensures suppliers provide sufficient capacity to guarantee that reliability targets are satisfied. The Act also implies an expanded role for the PUB, including dispute resolution in case of conflict between the System Operator and market participants. Specific reliability obligations are also contained in NB Power's OATT.

On 1 October 2004, the New Brunswick System Operator is expected to become the reliability authority for the Maritime Control Area, which covers New Brunswick, Nova Scotia, P.E.I. and northern Maine. This area could eventually become a regional transmission organization. Currently, the three provinces and northern Maine benefit from reserve sharing agreements aimed at ensuring that the NPCC reserve criteria can fully be met.

3.8.2 Reliability Issues

The proposed refurbishment of the Point Lepreau nuclear power plant has created some uncertainty with respect to generation adequacy. The utility has actively pursued initiatives to minimize the risks associated with a shortage situation during the refurbishment period (2008-2009). These initiatives include assessments of gas-fired and coal-fired generation options, the conversion of Coleson Cove from heavy fuel oil to Orimulsion™, a public request for wind energy projects and assessment of other renewable resources. In addition, DSM options will be assessed as well as proposed new transmission facilities to increase import capability.

Another source of uncertainty is tied to recent announcements in the news media that Orimulsion™ supply for the Coleson Cove plant could be in jeopardy. Conversion of the plant to Orimulsion™ is nearing completion; however, it has been reported that, to date, NB Power has been unable to secure a long-term supply of this fuel. As indicated above, the Point Lepreau life-extension project is tied to the repowering of Coleson Cove from heavy fuel oil to Orimulsion™.

Current import constraints limit the province's ability to benefit from surplus power that may exist south of the border. Import capability on the 345 kV line is practically zero because flows coming into New Brunswick are restricted while the Point Lepreau generating station is operating. In the event that Point Lepreau tripped, voltage and stability problems would occur in Maine and potentially cause an outage of the 345 kV line, which could lead to a blackout in the Maritime Control Area. The utility has obtained approval from the NEB to construct a second 345 kV transmission line and interconnection to Maine. The new line, expected to be built by 2006, would be used for import and export opportunities and provide improved system reliability for the Maritimes area. It could also offset the potential generation deficit anticipated during the refurbishment of the Point Lepreau nuclear plant.

NB Power continues to be open to the development of the Neptune Project, a proposed merchant undersea DC transmission system. If fully completed, the project would connect generation sources in Maine, New Brunswick and Nova Scotia, to markets in Boston, New York City, Long Island and Connecticut.

Additionally, the utility has been involved in discussions regarding the creation of a northeastern regional transmission organization, which would cover New York, New England and New Brunswick. Creation of an RTO should improve transmission access to a larger market and enhance overall system reliability.

3.8.3 Summary

NB Power is a full member of NPCC and meets its adequacy requirements through capacity sharing agreements with neighbouring systems. With restructuring scheduled to be implemented on 1 October 2004, the New Brunswick System Operator will become the reliability authority for New Brunswick. Reliability could be enhanced with expanded import capability, which is currently constrained.

3.9 Prince Edward Island

Maritime Electric Company Limited (Maritime Electric), a wholly-owned subsidiary of Fortis Inc., is the principal electricity distributor in the province. Most of the energy supplied to end-users is purchased from NB Power. Maritime Electric's mandate is to "provide the most reliable energy at the lowest possible cost while maintaining a high level of customer service."

The provincial network is connected to the mainland power grid via two 138 kV submarine cables with a total transfer limit of 200 MW and includes over 5 000 km of distribution lines. Maritime Electric maintains on-island backup generating facilities at Charlottetown (60 MW) and Borden (40 MW). It also buys wind energy produced at North Cape which can supply approximately four percent of the island's annual electricity usage.

Electricity accounts for about 13 percent of provincial end-use energy demand. Nearly 45 percent of electricity demand occurs in the commercial sector, 40 percent in residential and 15 percent in industrial. Maritime Electric serves 68 000 customers and meets a peak demand of 203 MW.

3.9.1 Reliability Framework

In fall 2003 legislation was passed which returned Maritime Electric to a traditional cost of service regulatory regime, beginning 1 January 2004. Under the *Electric Power Act*, the Island Regulatory and Appeals Commission has responsibility for Maritime Electric's operations, electricity rates and all capital investment projects.

The province is part of the NPCC/Maritimes control area which also includes New Brunswick, Nova Scotia and northern Maine. The main criterion Maritime Electric uses for long-term generation planning is the requirement under the terms of the interconnection agreement with NB Power to maintain a reserve margin equal to 15 percent of firm peak load. For operations, Maritime Electric provides for its share of the control area's reserve needed to meet the NPCC requirement to have enough generation to cover the first contingency (loss of the largest unit) within 10 minutes, plus 50 percent of the second contingency within 30 minutes.

3.9.2 Reliability Issues

Maritime Electric faces two main reliability issues. The first is the loading on the interconnection with NB Power. Within several years the P.E.I. load is expected to increase to the level that, if one of the submarine cables were out of service, the capacity of the remaining cable plus the existing on-island generating capacity would not be sufficient to meet the system peak load. This issue could be addressed by increasing the capacity of the interconnection with NB Power or by installing additional generating capacity on P.E.I. If the capacity of the interconnection were to be increased, it would be by installing a 200 MW cable inside the Confederation Bridge.

The second reliability issue facing Maritime Electric is the uncertainty about the adequacy of generating capacity in the Maritime provinces. Maritime Electric's plan to address these two issues is to install a 50 MW light oil fired combustion turbine on the Island. This project will serve two purposes. It will provide additional backup for the existing submarine cables and it will provide Maritime Electric with 50 MW of needed generating capacity. An additional feature of the project is that the unit will be capable of being converted to natural gas if gas becomes available on P.E.I.

Maritime Electric has participated in discussions regarding the possible creation of a northeastern RTO which would cover the Maritime provinces and northern Maine. Potential benefits for P.E.I.

include increased access to diversified supply sources, which could have a positive reliability impact for the island.

NB Power has recently undertaken some transmission upgrades in the southeastern part of New Brunswick that will reduce losses on the lines supplying the interconnection to the island and improve reliability, but these upgrades will not by themselves significantly increase the transfer capability of the interconnection.

3.9.3 Summary

The Province of Prince Edward Island relies primarily on generation sources in New Brunswick to meet on-island load requirements. Legislation passed in fall 2003 has returned Maritime Electric to cost of service regulation. Maritime Electric is pursuing the installation of a 50 MW light oil-fired combustion turbine to address interconnection reliability and generation adequacy issues.

3.10 Nova Scotia

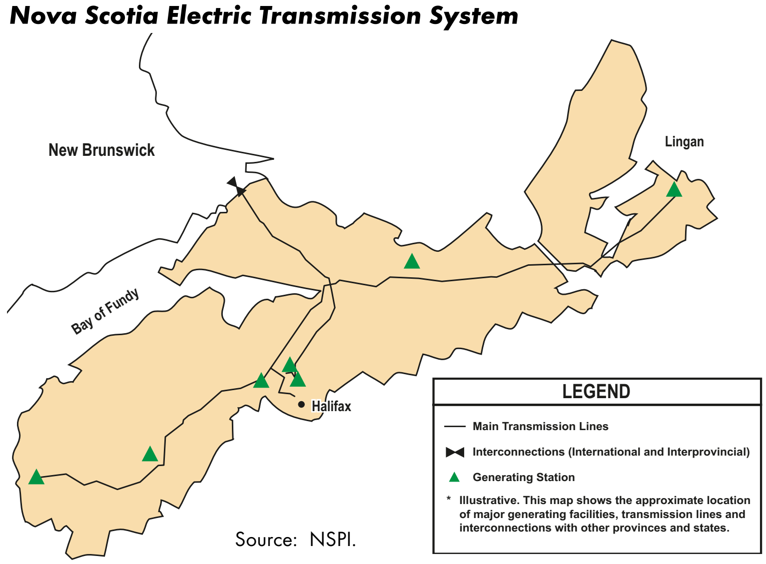
Nova Scotia's current electrical industry is a regulated monopoly. Nova Scotia Power Inc. (NSPI), a subsidiary of Emera, an investor-owned company, is a cost-of-service, vertically-integrated electric utility. NSPI is the predominant electricity supplier in the province, owning and operating approximately 97 percent of generation, 99 percent of transmission, and 95 percent of the distribution systems in the province. The remaining distribution is owned and operated by six municipal utilities.

In December 2001, the Province of Nova Scotia released an Energy Strategy and has subsequently taken significant steps towards restructuring its electricity sector. In October 2003, an Electricity Marketplace Governance Committee (EMGC) submitted a report that contains recommendations on the industry structure, market rules and implementation of the Energy Strategy. In the following month, the Government announced its adoption of these recommendations and stated that "sustaining a reliable electricity supply will be the province's number one priority as it makes changes to Nova Scotia's electricity system to increase competition and encourage more renewable energy sources." A key element of Nova Scotia's restructuring plan is the introduction of competition within the electrical sector in a staged manner, beginning with wholesale access expected to occur in January 2005.

Electricity accounts for approximately 20 percent of Nova Scotia's end-use energy demand. About 37 percent of electricity demand originates from the residential sector. The commercial and industrial sectors account for 27 and 36 percent, respectively. Peak electricity demand in 2002 was 2 078 MW.

FIGURE 3.12

Nova Scotia Electric Transmission System



Source: NSPI.

The province relies on in-province generation sources to meet its electrical load requirements. Approximately 75 to 80 percent of the province's generation comes from coal-fired thermal plants, the largest being the 620 MW Lingan plant. The remaining 20 to 25 percent originates from the Tufts Cove plant (dual-fired heavy fuel oil/natural gas), as well as from several oil-fired thermal plants and hydro stations. Additionally, some electricity is generated at a tidal plant and at a 1.2 MW wind farm.

Total generating capacity is comprised of 2 184 MW at NSPI's thermal and hydropower facilities, and 25 MW contracted with independent power producers. This capacity includes a planned reserve margin of at least 20 percent, which can be increased further with an interruptible load of 16 percent.

NSPI's network includes 5 400 km of high voltage transmission lines (69 kV and up) and interconnects with NB Power's system via a 345 kV line and two 138 kV lines. Under most conditions, the transfer limits to and from New Brunswick are 350 MW and 300 MW, respectively. A reserve sharing agreement exists between NSPI and NB Power, allowing them to combine reserve capacity to meet NERC/NPCC reliability standards.

3.10.1 Reliability Framework

Provincial legislation assigns to the Nova Scotia Utility and Review Board (UARB) the mandate to ensure that NSPI fulfills its "obligation to supply" in a reliable manner and at regulated prices. The UARB regulates all aspects of NSPI's operations and planning, including reviews and approvals regarding rates, capital spending, and return on equity. With respect to reliability, NSPI is subject to performance review and oversight by the UARB.

NSPI assumes the responsibility of a central supply planner. The Energy Strategy stated that, under its obligation to serve customers in Nova Scotia, NSPI has the "sole responsibility for maintaining adequate supplies of electricity in the province." The utility must ensure that it has adequate and reliable supplies, including sufficient reserves to deal with expected load growth as well as planned and forced outages. As part of its resource planning process, NSPI forecasts future peak loads and determines reserve requirements. These two factors establish the amount of capacity required to reliably serve customer loads. A first contingency limit (n-1) has been part of NSPI's planning criteria for designing new facilities.

NSPI acts as the exclusive reliability authority in the province. Its energy control centre performs short-term adequacy analyses, approves the day-ahead forecasts of generation and provides economic dispatch to the system. The provincial electricity grid includes utility as well as non-utility generation sources. Operating agreements with non-utility generators require them to notify the energy control centre when they are unavailable.

As a full and voting member of the NPCC, NSPI adheres to NPCC reliability standards, participates in the standards development process and has the responsibility to support the interconnected system. It is also subject to reliability audits by the NPCC. Although there is no specific reporting requirement on reliability from the UARB, the utility periodically reports to the regulator on reliability indexes such as SAIFI and SAIDI.

As the wholesale power market opens in 2005, the UARB is expected to assume new responsibilities, including: transmission overseer; arbiter of disputes between market participants; market surveillance; and the licensing of retail sellers. NSPI will become a functionally unbundled utility. A System Operator will be established and will play a central role in the operation of the restructured market while ensuring security and reliability of the system. It will also be responsible for dispatch, as well as providing ancillary services and scheduling transactions on the interties.

NSPI has developed time-of-use rates to provide incentives for load shifting from peak to off-peak periods.

3.10.2 Reliability Issues

Under the current monopoly framework, reliability responsibility, management and oversight are centralized. In a restructured market, many aspects of reliability management and oversight will change: the number of market participants will increase; reliability responsibilities will be shared between several entities; and there will be new market rules. The transition to restructured markets requires the assignment of well-defined roles and responsibilities to all parties involved in ensuring reliability.

Coal-fired generation in the province is a major source of greenhouse gas emissions. The prospects of early retirement of coal-fired power plants have raised some uncertainties and concern with respect to supply adequacy. An accelerated coal phase-out program could imply significant investments in new generation capacity (e.g., gas-fired power plants) and/or more reliance on imports.

Another issue relates to the fact that currently, small amounts of non-dispatchable generation or variable generation are incorporated into NSPI's system without an appreciable impact on economic system operation and reliability. As this form of generation is expected to increase in a restructured environment, its impact could be increasingly felt. On the other hand, NSPI serves about 380 MW of interruptible loads, giving it substantial flexibility to ensure firm load is served during periods of supply and transmission constraints.

Reliability performance can also be measured by the response time after an outage, i.e., the time the utility takes to restore power to its customers. Hurricane Juan, which hit Nova Scotia in September 2003, provides a recent example of how quickly service can be restored. According to a report submitted to the UARB, NSPI stated Hurricane Juan caused the most damage ever to its transmission and distribution system. The utility also reported that within five days of the Hurricane, 95 percent of those who lost power (close to 300 000 customers) had service restored. A survey revealed that nearly 90 percent of customers said they were satisfied with NSPI's response to the outage.

3.10.3 Summary

Electric power reliability is primarily the responsibility of NSPI, which is subject to performance review and oversight by the UARB. NSPI complies with NERC and NPCC reliability standards and has its own specific internal programs and operational criteria to maintain system reliability.

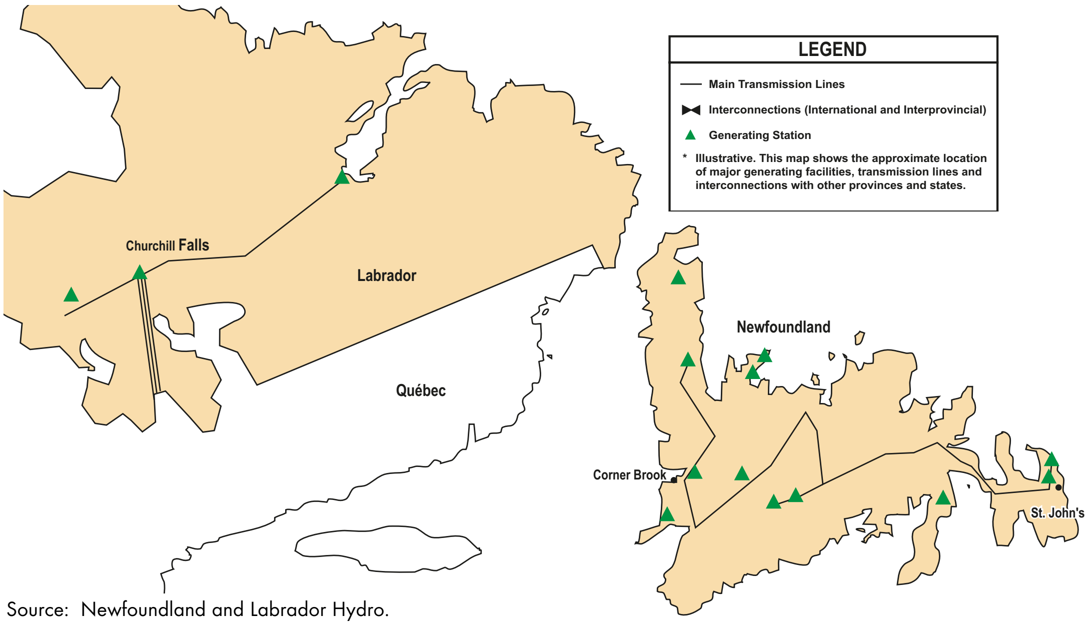
3.11 Newfoundland and Labrador

In the Province of Newfoundland and Labrador, electricity markets are served by two major utilities. Newfoundland and Labrador Hydro (Hydro), a Crown corporation, is the principal generator and power transmitter in the province. Newfoundland Power (a subsidiary of Fortis Inc., an investor-owned company) is the principal distributor on the island portion of the province. Newfoundland Power purchases about 90 percent of its supply requirements from Hydro and generates the remaining balance from its own facilities.

The province has two distinct electric power systems, the island interconnected system and the Labrador system. The latter has an intertie with Québec via three 735 kV lines, with a total transfer capability of 5 200 MW.

F I G U R E 3 . 1 3

Newfoundland and Labrador Electric Transmission Systems



Source: Newfoundland and Labrador Hydro.

Electricity represents about 30 percent of total end-use energy demand in the province. Demand is concentrated on the island, which registered a peak of 1 403 MW in 2002. The residential sector accounts for about 60 to 65 percent of total demand on the island, the balance comes primarily from the commercial sector.

Generation on the island reflects a mixture of about two-thirds hydro and one-third thermal. In Labrador, generation is predominantly hydroelectric. Electricity produced at Churchill Falls (5 428 MW) is mostly destined for Québec.

3.11.1 Reliability Framework

Three primary pieces of legislation govern the electricity industry in the province: the *Public Utilities Act* (PUA), the *Newfoundland and Labrador Hydroelectric Corporation Act* (the Hydro Corporation Act) and the *Electrical Power Control Act 1994* (EPCA). The Public Utilities Board (PUB) has legislated responsibilities for oversight and monitoring of electric utilities in the province. According to section 3(b) of the EPCA, the PUB is responsible for ensuring that “the production, transmission and distribution of power in the province should be managed and operated in a manner: (i) that would result in the most efficient production, transmission and distribution of power, (ii) that would result in consumers in the province having equitable access to an adequate supply of power and (iii) that would result in power being delivered to consumers in the province at the lowest possible costs consistent with reliable service.”

Hydro and Newfoundland Power are regulated by the PUB under traditional rate-based regulation. All capital investments, including those associated with reliability, need to be reviewed and approved by the PUB. While the PUB is ultimately responsible for reliability oversight, Hydro acts as the principal reliability and balancing authority with respect to generation and transmission in Labrador and on the island. The provision of reliability at the distribution level on the island is the main responsibility of Newfoundland Power. Neither utility is a member of NERC, nor are they subject to compliance with NERC reliability standards.

For generation planning, reliability criteria set the minimum level of reserve capacity and energy in the system. The energy criterion ensures that the island system has sufficient firm energy capability to meet firm energy requirements. The capacity criterion is based on a maximum target of 2.8 hours of outages per year (resulting in a reserve margin of approximately 15 to 19 percent depending on system resources). Facility investments are planned on the basis of long-term load forecasts and system expansion studies, and take into account the trade-off between costs and reliability. To reduce risks of outages, regular maintenance and inspection of assets, redundancy of critical facilities and other loss prevention solutions are utilized.

Outage frequencies and durations are reported regularly to the PUB with comparisons to average industry performance. Quarterly indices include SAIFI, SAIDI and the System Average Restoration Index. Annual indices include the Derating Adjusted Forced Outage Rate[50] and the Weighted Incapability Factor.

With respect to demand-side management, Newfoundland Hydro has developed “HYDROWISE,” an energy conservation initiative. In partnership with the Conservation Corps of Newfoundland and Labrador, Hydro also provides specialized energuide and energy audit services to customers. Newfoundland Power provides energy use advice to its customers under its Bright Ideas initiatives. These initiatives include financing and rebates to customers for insulation upgrades, and promotion of R2000 construction.

3.11.2 Reliability Issues

In Labrador, reliability is enhanced by the entitlement to generation from Churchill Falls. On the island, the age of many facilities (approaching 40 years) is a key industry concern and an important consideration in establishing utility capital investment. Hydro recently completed a multi-year transmission upgrade program at a cost of $45 million. This program, resulting from the redesign of the steel tower, 230 kV transmission lines from Sunnyside to St. John’s, involved re-conductoring, re-insulation, and the addition of new towers and strengthening of existing towers. Other investments have been made in recent years by Newfoundland Power to enhance reliability.

Due to the absence of interconnection with the mainland, the island can only rely on local generation sources. On the other hand, the island’s system is not exposed to risks associated with interconnection to other jurisdictions. The eventual construction of a transmission link between Labrador and Newfoundland would provide access to the hydro resources of Labrador and therefore would enhance the reliability and security of the Newfoundland system. It would also have favourable environmental impacts through displacement of existing fossil fuel generation.

3.11.3 Summary

Newfoundland and Labrador is served by two distinct electric power systems, with interconnection to the Québec grid from Labrador. Reporting on reliability performance is part of ongoing regulatory requirements. Construction of a power line from Labrador could enhance reliability on the island. In consideration of the age of facilities, utilities have constantly invested to promote system reliability.

50 Forced derating refers to an unplanned component failure or other condition that requires the output of the unit be reduced immediately or before the next weekend.

Summary

This report has provided an overview of electric reliability across Canada focusing on regional reliability frameworks and reliability issues. Based on the information presented, the following summarizing points can be made.

Reliability frameworks across Canada are diverse and evolving.

The electric industry in Canada has historically evolved along provincial lines with federal involvement focused on trade and international power lines. The reliability framework, in terms of the roles of the provincial or territorial governments, the regulators and market participants are diverse with the type and extent of oversight varying among the provinces. As restructured markets are introduced and mature, and provincial electricity policy changes, responsibilities for reliability tend to evolve. Often, the provincial approach for ensuring reliability is augmented by a legislated obligation on utilities to provide reliable electric service.

Restructuring introduces opportunities and challenges in maintaining reliability.

In a restructured market, many aspects of reliability management and oversight become more complex as the number of market participants increases and reliability responsibilities are shared among a number of entities. To date, the implementation of restructuring has both facilitated and impeded reliability. For example, after competition was introduced in Alberta's generation sector, investment in generation capacity increased. However, in most restructured markets, investment in transmission capacity has been lagging.

Reliability expectations vary.

A recent CEA survey found that Canadian distribution systems were available 99.95 percent of the time. However, expectations about an acceptable level of reliability vary across consumer sectors and regions. For industrial users, and increasingly in the commercial and residential sectors, good reliability includes continuity of service and considerations of power quality, such as appropriate voltage control. The challenge for industry, government and regulators is to find the optimum level of reliability given the diverse requirements.

Reliability can be gauged using performance measures.

Reliability performance can be assessed separately for the generation, transmission and distribution sectors and on a system wide basis. Several measures have been developed by industry with the most common addressing the duration and frequency of interruptions. Many utilities develop additional performance measures to focus on specific reliability issues within their provinces. Although governments and/or regulators usually have access to utility performance data on reliability, depending on the province, public access is limited. Notwithstanding that some performance data may be sensitive, commercially or otherwise, there is a public desire for greater transparency and availability of information. Furthermore, the Final Report on the August 14, 2003 Blackout identified the need to establish an independent source of reliability performance information with common definitions and data collection standards.

Reliability has a cost.

Reliability can be improved by making investments in infrastructure and technology; however, the cost of providing electricity will increase. Investments can be aimed at outage prevention, outage containment and/or service restoration. Each electric power system has a different generation mix, load profile, and system configuration so planners must find the best strategy to manage the risks for their particular system. To optimize reliability investments, planners must ensure the cost of initiatives is justified financially, socially and environmentally in terms of benefits or avoided costs. Utilities and other planners are challenged with achieving an acceptable level of reliability while keeping rates at reasonable levels.

Interconnections enhance reliability.

Under normal operating conditions, interconnections between power systems improve reliability and provide commercial benefits. These connections allow adjoining utilities to optimize the use of their resources and can contribute to meeting reserve requirements. Electricity can flow where it is needed, either to prevent system disturbances or to provide lower-cost power. However, a disturbance in one system, if it is severe enough, can also affect adjoining systems, thereby exposing a local system to regional weaknesses. The consensus is that the benefits outweigh the potential risks and the industry trend is toward strengthening the overall interconnected system.

Demand-side actions can enhance reliability.

Consumer behaviour and actions can enhance reliability through reducing overall electricity consumption and/or deferring consumption to non-peak periods. Demand-side management initiatives, such as energy conservation programs, can help maintain system adequacy for longer periods through levelling or reducing overall energy demand. Demand response initiatives, such as time-of-use pricing, can reduce seasonal or daily demand peaks such that investment in additional capacity for serving peak load may be avoided. To improve the success of demand programs, there is a need to develop proper incentives to motivate consumers to respond effectively.

Regional Electric Reliability Oversight

Province or Territory	Primary Legislation	Regulator	Primary Reliability Authority	NERC Region Member	Interconnections
British Columbia	*Utilities Commission Act, BC Hydro and Power Authority Act, Transmission Corporation Act*	British Columbia Utilities Commission	BC Transmission Corporation	yes	AB WA
Yukon	*Public Utilities Act of the Yukon*	Yukon Utilities Board	Yukon Energy Corporation, Yukon Electric Company Ltd.	no	none
Northwest Territories	*Northwest Territories Power Corporation Act*	Public Utilities Board of the NWT	Northwest Territories Power Corporation	no	none
Nunavut	*Quilliq Energy Corporation Act*	Utility Rates Review Council (limited to capital expenditures and rate review)	Nunavut Power Corporation (subsidiary of Quilliq Energy Corporation)	no	none
Alberta	*Electric Utilities Act*	Alberta Energy and Utilities Board	Alberta Electric System Operator	yes	BC SK
Saskatchewan	*Power Corporation Act, Crown Corporations Act*	SaskPower reports to Minister. Rates are reviewed by Saskatchewan Rate Review Panel.	Saskatchewan Power Corporation (SaskPower)	no	AB MB ND
Manitoba	*Manitoba Hydro Act*	Public Utilities Board (limited to rate review)	Manitoba Hydro	yes	SK ON ND MN
Ontario	*Electricity Act, 1998, Ontario Energy Board Act,1998*	Ontario Energy Board	Independent Market Operator (IMO)	yes	QC MB NY MI MN
Québec	*Act Respecting the Régie de l'énergie*	Régie de l'énergie	Hydro-Québec (TransÉnergie)	yes	NF NB ON NE NY
New Brunswick	*Electricity Act*	Board of Commissioners of Public Utilities	NB Power Corporation	yes	NS PEI QC ME
Prince Edward Island	*Electric Power Act*	Island Regulatory and Appeals Commission	Maritime Electric Company Limited	no	NB
Nova Scotia	*Utility and Review Board Act*	Nova Scotia Utility and Review Board	Nova Scotia Power Inc. (subsidiary of Emera)	yes	NB
Newfoundland & Labrador	*Newfoundland and Labrador Hydroelectric Corporation Act, Public Utilities Act, and Electric Power Control Act 1994*	Public Utilities Board	Newfoundland and Labrador Hydro, and Newfoundland Power	no	QC

GLOSSARY

Adequacy	One of the two basic functional aspects in defining the reliability of bulk power electric systems, which is the ability to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. The other basic aspect is operating reliability (NERC).
Alternating Current (AC)	An electrical current that reverses direction at regularly recurring intervals with alternately positive and negative values, averaging zero. Almost all electric utilities generate AC electricity as its voltage is easily transformed to higher or lower values.
Ancillary Services	Functions required in support of the reliable operation of the transmission and generation system. They are controlled by the system operator and include various types of operating services such as frequency and voltage control, load following, spinning reserve, and blackstart capability.
Bulk Power System	A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and transmission system.
CAIDI	Customer Average Interruption Duration Index. This is one of many indicators that can be used to measure the performance of transmission and distribution systems. CAIDI measures the average length of time per service interruption in a given time period (e.g., 1.8 hours per service interruption in 2002).
Capacity	The maximum amount of power that a device can generate, utilize or transfer, usually expressed in megawatts.
Cascading Blackout	The uncontrolled, successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
Commercial Sector	The commercial sector is generally defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social and educational institutions.

Congestion	Congestion occurs when a transmission system cannot accommodate all transactions that would normally occur, for example, due to capacity constraints or reliability considerations.
Demand Response (DR)	Reduction in electricity use in response to peak pricing or request from the system operator or a Load Serving Entity.
Demand-Side Management (DSM)	Actions undertaken by a utility that result in a change and/or reduction in demand for electricity. This can eliminate or delay new capital investment for production or supply infrastructures and improve overall system efficiency.
Direct Current (DC	Electric current that flows in one direction with little or no voltage fluctuation.
Distribution	The transfer of electricity from the transmission network to the consumer.
Diversity	The difference in peak demand on a daily or seasonal basis between regions. For example, peak demand generally occurs during the winter in Canada, while it occurs in the summer in some states. Diversity can be used as a basis for trade.
Eastern Interconnection	One of the three major "interconnections" that make up the North American power grid. It includes: the provinces east of Alberta, with the exception of Newfoundland; and the central and eastern states, a small part of Texas and parts of those western states not included in the Western Interconnection. From the standpoint of electric reliability, the Eastern Interconnection covers the same electrical jurisdictions as eight NERC regional councils (NPCC, ECAR, FRCC, MAIN, MAPP, MAAC, SPP and SERC).
ERCOT	Electric Reliability Council of Texas. It is one of the three major interconnections that make up the North American power grid and includes most of the state of Texas. From the standpoint of electric reliability, ERCOT constitutes one of the NERC regional councils.
FACTS or FACTS Devices	Flexible Alternating Current Transmission System devices. These include a variety of electronic devices used to improve the control and stability of the transmission grid. The increased ability to direct power flow and the very fast response to system conditions enable the transmission system to be operated closer to its thermal limits, thus improving transmission efficiency.
Final Report on the August 14, 2003 Blackout	*Final Report on the August 14, 2003 Power Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 4004
Firm Load	Power or capacity that is intended to be available at all specified times during a period covered by an agreement respecting the sale thereof.

Generation	The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced.
Green Power	Electricity generation deemed to be environmentally less intrusive than most traditional generation, usually in accordance with standards established by government or regulatory agencies. Green power sources include wind, water, landfill gas, solar and others.
Greenhouse Gases	Gases such as carbon dioxide, methane and nitrous oxide, which actively contribute to the atmospheric greenhouse effect, i.e., increased temperatures in the earth's lower atmosphere.
Heritage Pool	An amount of energy and capacity determined by the existing generation assets which resulted from past decisions under a previous market regime. This energy is generally sold into the marketplace at a price reflecting historical costs.
High Voltage Direct Current (HVDC)	This technology is used to solve the problem of transmitting electricity over long distances. Direct current power loss over long distances is considerably less than alternating current. A higher voltage is used with direct current to increase energy transmission and reduce losses.
Industrial Sector	The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments.
Interruptible Load	Power that is made available under an agreement that permits curtailment, interruption or cessation of delivery at the option of the supplier.
Independent System Operator (ISO)	An ISO is functionally separated from other electricity market participants, i.e., generators, transmission companies and marketers, and makes non-discriminatory access available to users of the transmission system. The ISO is responsible for monitoring and controlling the transmission system in real time.
IOR	Index of Reliability. This is one of many indicators that can be used to measure the performance of transmission and distribution systems. IOR measures the relative amount of time a system is available, or is able to provide service, in a given time period (e.g., an IOR of .9995 in 2002 indicates a system provided service 99.95 percent of the time in 2002).
Joule	A unit of work and energy. It is defined as the work done (energy transferred) in one second by a current of one ampere at a potential difference of one volt. One watt is equal to one joule per second.

Kilowatt hour	A measure of electric energy; the amount of electric energy required to operate ten 100-watt light bulbs for one hour.
North American Power Grid	The North American network of high-voltage transmission lines involved in the transfer of power between generating plants and customer loads (mainly distribution companies and large industrial consumers). The "grid" is composed of three major electrical "interconnections," known as the Western Interconnection, the Eastern Interconnection and ERCOT, which together include: most of Canada; the continental United States (excluding Alaska); and a northern section of the Baja California Norte, Mexico. The major interconnections are electrically independent, meaning that, within each interconnection, the (AC) frequencies are "synchronous" and electrical loads are balanced with generation. The interconnections are linked by DC transmission lines.
Off-Peak	Hours of the day (e.g., from 11:00 p.m. to 7:00 a.m., Monday to Friday and all day Saturday and Sunday) or other periods (e.g., seasonal) with lower electrical demand.
On-Peak	Hours of the day (e.g., from 7:00 a.m. to 11:00 p.m., Monday to Friday) or other periods (e.g., seasonal) with higher electrical demand.
Open Access	Non-discriminatory access to electricity transmission lines.
Operating Reliability	One of the two basic functional aspects in defining the reliability of bulk power electric systems, which is the ability to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements. The other basic aspect is adequacy (NERC).
Peak Load	The maximum load consumed or produced by a unit or group of units in a stated period of time.
Rate	The price charged for a commodity or service. Rates may be subject to regulatory approval or may be set by the marketplace.
Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities and directly influences electric system voltage.
Reciprocity or Reciprocal Access	Refers to the reciprocity requirement under FERC Order 888, which states that transmission customers taking delivery under an open access transmission tariff must offer, in return, open access to the transmitting utility.

Regional Transmission Organization	A voluntary organization of transmission owners, transmission users, and other entities approved by the U.S. Federal Energy Regulatory Commission (FERC) to efficiently coordinate transmission planning (and expansion), operation, and use on a regional (and interregional) basis.
Reliability	The degree of performance of the elements of the bulk electricity system that results in electricity being delivered to customers within accepted standards and in the amounts desired. Reliability can be addressed by two basic and functional aspects of the electric system, adequacy and operating reliability (NERC).
Reserve Margin	The amount of unused available capability of an electric power system at peak load as a percentage of total capability.
Residential Sector	Private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying.
Restructuring	Reorganizing electric utilities from vertically-integrated monopolies into separate generation transmission and distribution companies. This separation or unbundling is intended to promote competition between generators and to “open “the transmission and distribution systems, leading to increased competition in the supply and marketing of electricity.
Retail Access	A market in which electricity and other energy services are sold directly to consumers by competing suppliers. Also known as direct access.
Reverse Metering	An electricity consumer with generating capability may provide electricity to the grid, and it is subtracted from the metered amount of consumption for which the consumer must pay.
SAIDI	System Average Interruption Duration Index. This is one of many indicators that can be used to measure the performance of transmission and distribution systems. SAIDI measures the number of hours of service interruptions per customer in a given time period (e.g., 4.4 hours of service interruptions in 2002).
SAIFI	System Average Interruption Frequency Index. This is one of many indicators that can be used to measure the performance of transmission and distribution systems. SAIFI measures the number of service interruptions per customer in a given time period (e.g., 2.4 service interruptions in 2002).
Spot Market	Market where actual commodities or financial instruments are bought and sold for instant delivery. The spot market contrasts with the futures market, in which contracts are completed at a specified time in the future.

Tariff	The terms and conditions under which a service or product will be provided, including the rates or charges that users of a service or product must pay. Tariffs are usually proposed by the service or commodity provider, and are subject to regulatory approval.
Thermal Plants	Facilities which generate electricity using a steam turbine or combustion turbine driven by biomass, fossil fuels or nuclear power.
Time-of-Use Rates	Rates based on the time of day when the electricity is actually used. These rates allow consumers to pay less for the electricity they use during "off-peak," or low electrical demand periods. Electricity used during the" on-peak" hours is more costly.
Transmission	The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution.
Transmission Tariff	The authorized charge levied for provision and use of transmission services.
Unbundling	Separation of the vertically-integrated functions of utility companies into generation, transmission, distribution and energy services.
Utility	An entity owning and operating an electric system and having the obligation to provide electrical service to all end-users upon their request.
Vertically-Integrated Utility	A utility that combines the functions of generation, transmission and distribution.
Western Interconnection	One of the three major "interconnections" that comprise the North American power grid. It includes: British Columbia and Alberta; all or parts of the 13 western-most states of the continental U.S. (excluding Alaska) and a small part of Texas; and a northern section of the Baja California Norte, Mexico. From the standpoint of electric reliability, the Western Interconnection includes the same electrical jurisdictions as the WECC.
Wholesale Access	A distributor of power has the option of buying its power from a variety of power producers on a wholesale basis for resale on a retail level.
Wholesale Transactions	Transactions between electricity generators and retailers.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

55 Kenmount Road
PO Box 8910
St. John's, Newfoundland
A1B 3P6
Business: (709) 737-5600
Facsimile: (709) 737-2974
www.newfoundlandpower.com

HAND DELIVERED

December 21, 2006

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Peer Group Performance Measures for Newfoundland Power

On February 28, 2005, the Company submitted a report entitled *Peer Group Performance Measures for Newfoundland Power*. The report committed the Company to reporting annually on the measures presented therein until otherwise directed by the Board.

The report enclosed herewith is provided in fulfillment of that commitment.

We trust this is satisfactory. However, if there are any questions or concerns, they should be directed to the undersigned.

Yours very truly,

Gerard M. Hayes
Senior Counsel

c. Wayne D. Chamberlain
Newfoundland & Labrador Hydro

Tom J. Johnson
Consumer Advocate
O'Dea, Earle Law Offices

Join us in the fight against cancer.

Telephone: (709) 737-5609 Email: ghayes@newfoundlandpower.com Fax: (709) 737-2974

Peer Group Performance Measures For Newfoundland Power

December 21, 2006

NEWFOUNDLAND POWER
A FORTIS COMPANY

Peer Group Performance Measures
For Newfoundland Power

Table of Contents

1.0 Introduction

In Order No. P.U. 19 (2003), the Board of Commissioners of Public Utilities (the "Board") ordered that Newfoundland Power Inc. ("Newfoundland Power" or "the Company") file with the Board by March 31, 2004 a report suggesting a "peer group" of utilities and performance measures upon which to evaluate the Company's performance.

On March 1, 2004, the Company submitted a draft report entitled *A Report on Peer Group Performance Measures for Newfoundland Power* (the "Draft Report") which reviewed the Company's initial findings in relation to utility performance measures and benchmarking initiatives. The Draft Report recommended the adoption by the Board, on an interim basis, of several performance measures that could be used to benchmark Newfoundland Power's performance against composite performance measures available from the Canadian Electricity Association's (CEA) Committee on Corporate Performance and Productivity Evaluation (COPE).

On March 19, 2004, the Board wrote to Newfoundland Power seeking clarification of certain matters relative to the recommendations contained in the Draft Report.

On March 31, 2004, Newfoundland Power submitted a report entitled *A Supplementary Report on Peer Group Performance Measures for Newfoundland Power* (the "Supplementary Report") addressing the questions contained in the Board's letter and recommending certain additional measures. In the Supplementary Report, Newfoundland Power indicated it would participate in the COPE 2003 data cycle, and report to the Board on its evaluation of the COPE process.

On February 28, 2005, the Company submitted a report entitled *Peer Group Performance Measures for Newfoundland Power* (the "February 2005 Report"), which provided comparative statistical data together with an assessment of the appropriateness of the recommended performance measures.

The February 2005 Report included comparisons between the Company and a composite of Canadian utilities and a composite of American utilities. The report indicated that, due to concerns with data availability and quality and observed differences in participating utilities' operating profiles, it was not possible for Newfoundland Power to draw meaningful conclusions regarding the Company's performance through comparisons with others. The February 2005 Report also committed the Company to report annually on the measures presented until otherwise directed by the Board.

This report is provided in fulfillment of the Company's commitment to report annually on the measures presented in the February 2005 Report.

2.0 Performance Measures

This report provides a comparison of Newfoundland Power performance measures against the performance measures of a composite of Canadian and U.S. utilities.

2.1 Canadian Utility Measures

The following measures are presented for comparing the Company's performance against a composite of Canadian utilities:

1. Direct Distribution OM&A (operations, maintenance & administration cost) per circuit kilometre;
2. Direct Customer Service OM&A per customer;
3. Corporate Services OM&A as a percentage of Total Corporate OM&A;
4. Total Corporate OM&A per MWh;
5. System Average Interruption Frequency Index (SAIFI);
6. System Average Interruption Duration Index (SAIDI); and
7. All-injury Frequency Rate (Injuries per 200,000 hours worked).

Appendix A shows comparisons of the Canadian utility composite measures and the equivalent Newfoundland Power data. For this report, as with the previous reports, the Company used data from COPE, as well as information from the CEA's annual *Service Continuity Report on Distribution System Performance in Electrical Utilities* and Accident Statistics Reports. All of the CEA financial measures were obtained from COPE.

Due to concerns over changing data definitions and changes in participants, the CEA has restricted the data available for trending certain financial measures to composite information from those utilities that have reported data for each of the previous three years. Since only composite results are available, high and low range results are no longer included in the comparisons.

Appendix B contains the profiles of the Canadian utilities that participated in COPE in 2003.[1]

In 2005, the CEA issued a policy paper, *Benchmarking Data in Regulatory Settings,* regarding the appropriate use of CEA utility data in assessing utilities' performance in a regulatory setting. Appendix E contains the CEA policy paper.

The CEA policy paper states that it is currently developing appropriate benchmarking performance measures for use in a regulatory setting. The performance measures resulting from this review may or may not include the measures presented in this or previous reports and will be dependent upon their being considered appropriate for regulatory use by the CEA. The CEA currently restricts the use of data that it considers not appropriate for use in a regulatory setting. However, the CEA will allow utilities to use composite financial data for 2003 to 2005 during the transition period.

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1 A more recent version of this table is not available from COPE. Since 2003, FortisBC and Toronto Hydro are no longer participating in COPE, while Nova Scotia Power is participating.

2.2 U.S. Utility Measures

The following measures are presented for comparing the Company's performance to a peer group of U.S. utilities:

1. Total Distribution Operating Expense per Customer;
2. Total Distribution Operating Expense per MWh;
3. Total Customer Service Expenses per Customer;
4. Total Administration and Other Operating Expense per Total Operating Expense (Excluding fuel and purchased power);
5. Total Operations Expense per Energy Sold (Excluding fuel and purchased power); and
6. Total Operations Expense per Customer (Excluding fuel and purchased power).

All of these measures are based on information found in utility filings with the Federal Energy Regulatory Commission (FERC). FERC requires major electric utilities to annually file prescribed information regarding their operations. This principally involves the reporting of accounting information broken down in accordance with the FERC code of accounts. The FERC filings are public information.

Appendix C contains the comparisons of the composite measures for U.S. utilities and the equivalent Newfoundland Power data. For each measure, the number of utilities providing data for the composite information and the range of individual results is provided.

The measures for the U.S. data are presented without any adjustment for exchange rates. With the significant shifting in exchange rates since 1999, converting U.S. dollar figures to Canadian figures would greatly distort cost trends.

Appendix D is a list of the U.S. utilities from which the composite measures in Appendix C were compiled. The composite benchmark data for 2005 contains one less contributor than previous years, as New Hampshire Electric Cooperative Inc. did not file their data with FERC for 2005.

3.0 Summary and Conclusion

This report presents comparative utility data for a variety of measures of utility performance. The measures shown are the same measures as were provided to the Board in the February 2005 Report.

The February 2005 Report assessed a number of performance measures for comparing the performance of Newfoundland Power to other utilities. The Company concluded in the February 2005 Report that it was difficult to draw meaningful conclusions regarding the Company's performance through comparisons with other utilities. This is because of continued concerns with data availability and quality and observed differences in participating utilities' operating profiles. The Company's assessment remains unchanged.

Newfoundland Power will continue to report to the Board annually on the measures presented herein until otherwise directed by the Board.

Appendix A

CEA Composite Comparisons

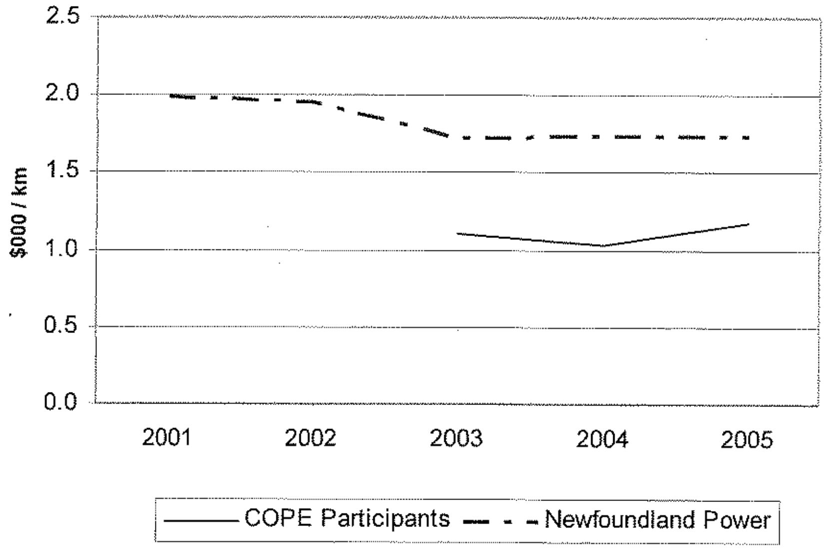
Appendix A

CEA Composite Comparisons

Table of Contents

Measure **Page**

Direct Distribution OM&A Per Circuit Kilometre
(2005$)



Year	CEA COPE Composite	Newfoundland Power
2001		1.989
2002		1.949
2003	1.102	1.726
2004	1.035	1.732
2005	1.173	1.737

This is the Direct Distribution OM&A per Circuit Kilometre measure as defined by CEA's Committee on Corporate Performance and Productivity Evaluation (COPE). It measures the total direct cost of operating labour and materials, excluding allocated corporate shared services, involved in the operation and maintenance of the distribution portion[2] of the electrical system, expressed on a per distribution circuit kilometre basis.

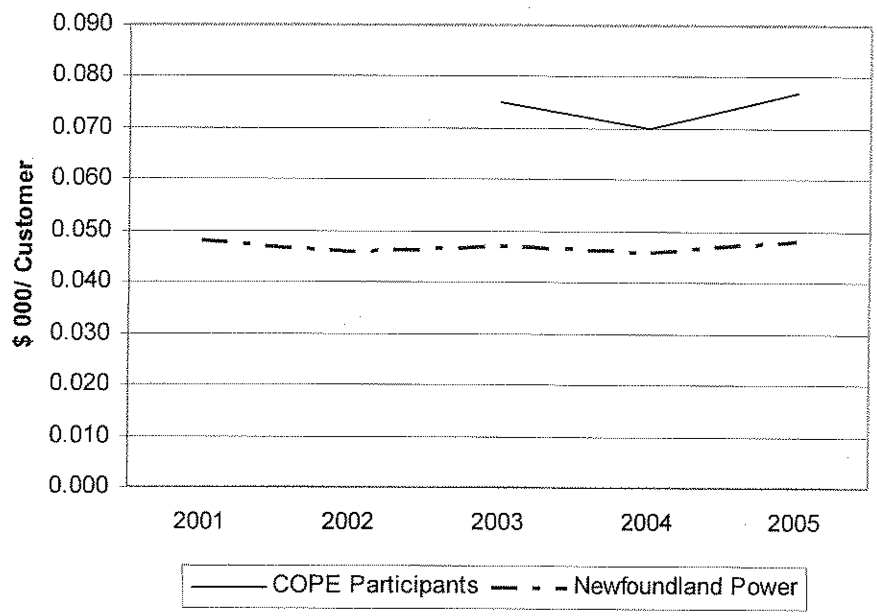
COPE composite data for trending purposes is only available for 2003, 2004, and 2005 and encompasses 10 reporting utilities.[3]

The trend line for Newfoundland Power shows a reduction in the Direct Distribution OM&A per Circuit Kilometre over the five year period. With only three years of historic CEA data available for trending, it is difficult to draw any definitive conclusions from comparison of the two trend lines.

2 The distribution system is the portion of the electrical system that links the transmission system to customer facilities.

3 Due to CEA restrictions on use of data for trending purposes, 2001 and 2002 composite data is not provided.

Direct Customer Service OM&A per Customer
(2005$)



Year	CEA COPE Composite	Newfoundland Power
2001		0.047
2002		0.046
2003	0.075	0.047
2004	0.070	0.046
2005	0.077	0.048

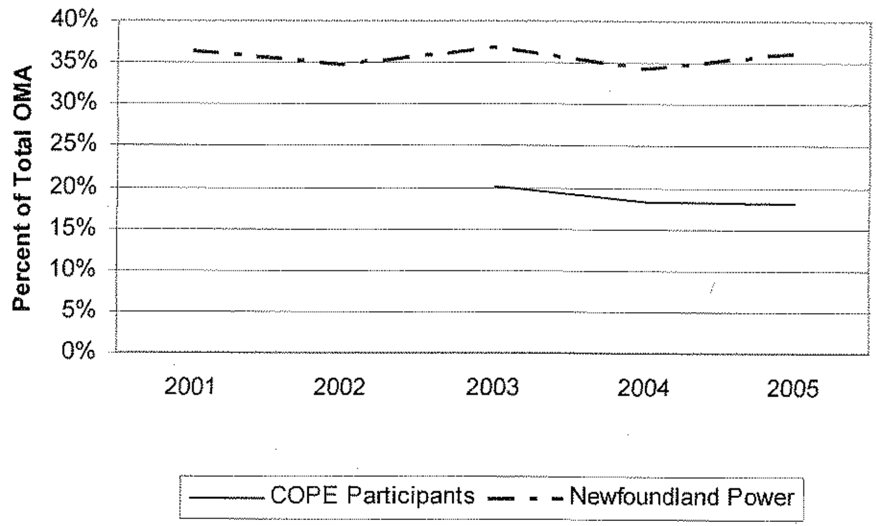
This is the Direct Customer Service OM&A per Customer measure as defined by COPE. It measures the total direct cost of operating labour and materials, excluding allocated corporate shared services, associated with the management of customer relations and billing functions, expressed on a per customer account basis.

COPE composite data for trending purposes is only available for 2003, 2004, and 2005 and encompasses 5 reporting utilities.[4]

The trend line for Newfoundland Power shows a relatively stable Direct Customer Service OM&A per Customer over the five year period. With only three years of historic CEA data available for trending, it is difficult to draw any definitive conclusions from comparison of the two trend lines.

[4] Due to CEA restrictions on use of data for trending purposes, 2001 and 2002 composite data is not provided.

Corporate Services OM&A as a Percentage of Total Corporate OM&A



Year	CEA COPE Composite	Newfoundland Power
2001		36.4%
2002		34.7%
2003	20.1%	36.8%
2004	18.2%	34.2%
2005	18.0%	36.3%

This is the ratio of Corporate Services OM&A expressed as a percentage of Total Corporate OM&A as defined by COPE. Corporate Services OM&A includes operating labour and materials associated with corporate shared services[5] compared to the total cost of operations, maintenance, and administration.

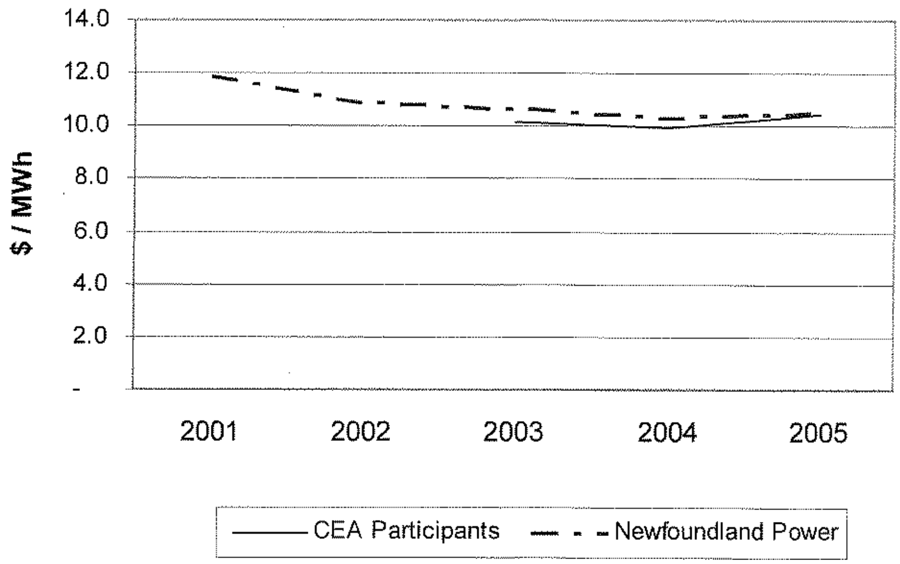
COPE composite data for trending purposes is only available for 2003, 2004, and 2005 and encompasses 8 reporting utilities.[6]

The trend line for Newfoundland Power shows a relatively stable ratio of Corporate Services OM&A to Total Corporate OM&A. With only three years of historic CEA data available for trending and a limited number of reporting utilities, it is difficult to draw any definitive conclusions from comparison of the two trend lines. While Newfoundland Power's number is higher than the COPE composite, it is more consistent with the US data. This may be attributable differences in accounting practices and operating profiles.

5 Includes corporate administration, legal, finance, human resources, internal audit, and information services functions.

6 Due to CEA restrictions on use of data for trending purposes, 2001 and 2002 composite data is not provided.

Total Corporate OM&A per MWh
(2005$)



Year	CEA COPE Composite	Newfoundland Power
2001		11.9
2002		10.9
2003	10.1	10.7
2004	9.9	10.3
2005	10.5	10.5

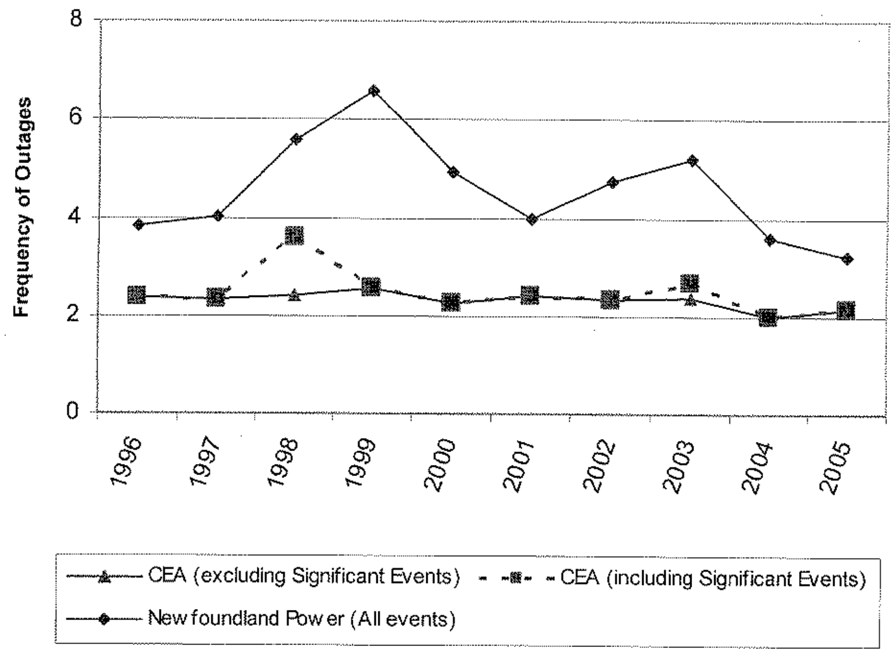
This is the ratio of Total Corporate Services OM&A per MWh delivered. Total Corporate OM&A includes all operating labour and materials for the electrical utility business. The MWh delivered figure includes both energy sold to end users and energy sold for resale.

COPE composite data for trending purposes is only available for 2003, 2004, and 2005 and encompasses 5 reporting utilities.[7]

The trend line for Newfoundland Power shows a reduction in the Corporate OM&A per GWh over the five year period. With only three years of historic CEA data available for trending, it is difficult to draw any definitive conclusions from comparison of the two trend lines.

[7] Due to CEA restrictions on use of data for trending purposes, 2001 and 2002 composite data is not provided.

System Average Interruption Frequency Index (SAIFI)



Year	CEA (Excluding Significant Events)	CEA (Including Significant Events)	Newfoundland Power
1996	2.39	2.39	3.82
1997	2.35	2.35	4.02
1998	2.40	3.58	5.60
1999	2.56	2.56	6.60
2000	2.26	2.26	4.93
2001	2.41	2.41	3.99
2002	2.33	2.33	4.76
2003	2.37	2.67	5.20
2004	1.98	1.98	3.58
2005	2.13	2.13	3.21

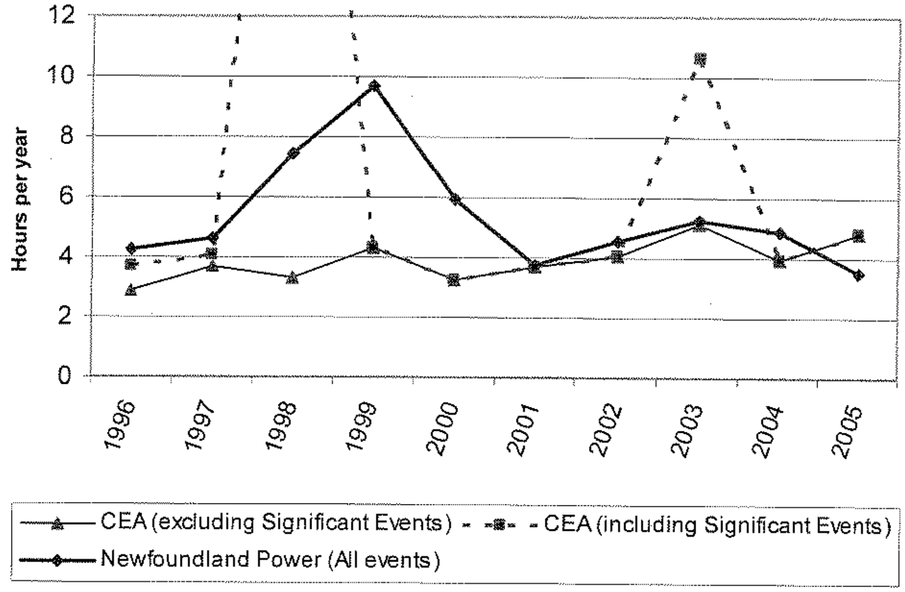
SAIFI is a standard industry index of the average annual cumulative frequency of service interruptions to customers.

The CEA trend line is the composite performance for over 30 Canadian participants (31 participants in 2005). The trend line shows significant variability year over year when significant events are included in the CEA data. While there appears to be a slight decline in the trend lines for Newfoundland Power and the CEA composite, this variability in the data makes it difficult to draw conclusions about any underlying trend. Also, technological advances that improved data collection may have impacted the trend in reliability data. This factor was recognized by COPE in the following statement:

> "It is important to note that technological advances in data collection systems coupled with additional rigor in the data processes as a result of utilities' increased focus on customer service and outage management implies that there has been additional improvement in the average number of outages experienced by customers that does not appear in the trend line." [8]

[8] *2003 Industry Evaluation Distribution Business Unit Executive Summary,* CEA COPE report, December 2004, page 5.

System Average Interruption Duration Index (SAIDI)



Year	CEA excluding Significant Events	CEA including Significant Events	Newfoundland Power
1996	2.86	3.67	4.23
1997	3.70	4.06	4.64
1998	3.32	30.31	7.41
1999	4.31	4.31	9.70
2000	3.23	3.23	5.93
2001	3.67	3.67	3.73
2002	4.06	4.06	4.54
2003	5.11	10.65	5.28
2004	3.95	3.95	4.86
2005	4.80	4.80	3.53

SAIDI is a standard industry index of the average annual cumulative duration of service interruptions to customers.

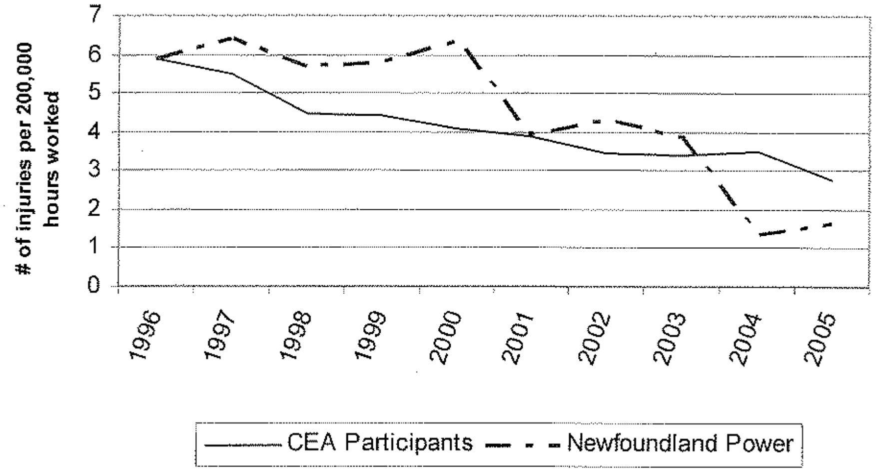
The CEA trend line is the composite performance for over 30 Canadian participants (31 participants in 2005). The trend line shows significant variability year over year, especially when significant events are included in the CEA data. The tread lines also appear to show a decline in SAIDI for Newfoundland Power and a slight increase in the CEA composite. The variability makes it difficult to draw conclusions about any underlying trend. Also, technological advances that improved data collection may have impacted the trend in reliability data. This factor was recognized by COPE in the following statement:

> "Though the data over the 10-year period shows a slight increase, technological advances in data collection systems coupled with additional rigor in the data collection processes as a result of utilities' increased focus on customer service and outage management implies there has been additional improvement in the average duration of outages experienced by customers that does not appear in the trend line data." [9]

The anomalous results evident in the "CEA including Significant Events" trend line reflect the Quebec ice storm in 1998 and the eastern North America power blackout in 2003.

[9] *2003 Industry Evaluation Distribution Business Unit Executive Summary,* CEA COPE report, December 2004, page 3.

All-injury Frequency Rate
(Injuries per 200,000 hours worked)



Year	CEA Composite	Newfoundland Power
1996	5.90	5.90
1997	5.51	6.44
1998	4.47	5.67
1999	4.41	5.84
2000	4.09	6.35
2001	3.91	3.96
2002	3.47	4.33
2003	3.41	3.87
2004	3.48	1.36
2005	2.76	1.65

This represents the rate of disabling injuries and medical aid injuries per 200,000 exposure hours (hours worked).

The CEA data is based on approximately 40 participating Canadian utilities (41 in 2005). Both the CEA and the Newfoundland Power trend line show a clear and comparable level of improvement.

Appendix B

2003 CEA Overall
Company Profile Matrix

2003 CEA COPE PARTICIPANTS COMPANY PROFILE

Sources: COPE's 2003 Executive Summary Report for the Distribution Business Unit, December 2004.

	ALM	ATE	BC	BCT	ENX	FAB	FBC	HQ	MH	NB	NP	HO	OTT	SK	SP	TH
Ownership	Private	-	Public	Public	Public	Private	Private	Public	Public	Public	Private	Public	Public	Public	Public	Public
Revenues ($000,000)	155	374	3,424	574	1,209	210	163	11,425	1,287	1,311	384	4,058	93	99	1,243	2,412
Employees (FTE)	225	851	4,406	304	1,084	795	379	21,410	5,118	2829	667	3,967	472	115	2,376	1,552
Gross Fixed Assets ($000,000)	1,557	2,202	15,293	3783	1,158	1,427	603	70,308	9,566	6,016	1,008	14,362	709	158	5,892	2,865
Business Unit Operations:																
Power Supply			X				X	X	X	X	X				X	
Transmission	X	X		X	X		X	X	X	X	X	X		X	X	
Distribution		X	X		X	X	X	X	X	X	X	X	X	X	X	X
Customer Service			X			X	X	X	X	X	X	X	X	X	X	X
Other Utility								X	X						X	
% Generation Split: H/F/N	0	0	90/10/0	0	0	0	100/0/0	96/1/3	98/2/0	23/60/17	0	0	0	0	19/81/0	0
Installed Capacity (MW)	0	0	11,300	0	0	0	205	33,614	5,481	3,770	144	0	0	0	3,194	0
Transmission Circuit Length (km)	11,551	8,606	-	18,300	280	0	1,722	39,177	20,370	6,686	2,062	28,621	0	37	12,863	0
Distribution Circuit Length (km)	-	62,281	56,534	-	6,556	95,581	5,372	106,074	86,775	19,990	8,397	119,000	4,870	782	140,733	16,400
Urban/Rural	Both	Both	Both	Both	Urban	Both	Both	Both	Both	Both	Both	Both	Both	Urban	Both	Urban
Customers Served (Meters)	-	174,147	1,635,388	-	368,673	394,600	90,325	3,592,677	501,356	316,319	213,203	1,126,522	267,337	57,000	432,644	668,673

ALM: AltaLink Management
BCT: BC TransCO
FBC: FortisBC
NB: New Brunswick Power
OTT: Hydro Ottawa
TH: Toronto Hydro

ATE: ATCO Electric
ENX: ENMAX
HQ: Hydro-Québec
NP: Newfoundland Power
SK: City of Saskatoon Electric System

BC: BC Hydro
FAB: FortisAlberta
MH: Manitoba Hydro
HO: Hydro One
SP: SaskPower

Appendix C

American (U.S.) Peer Group Composite Comparisons

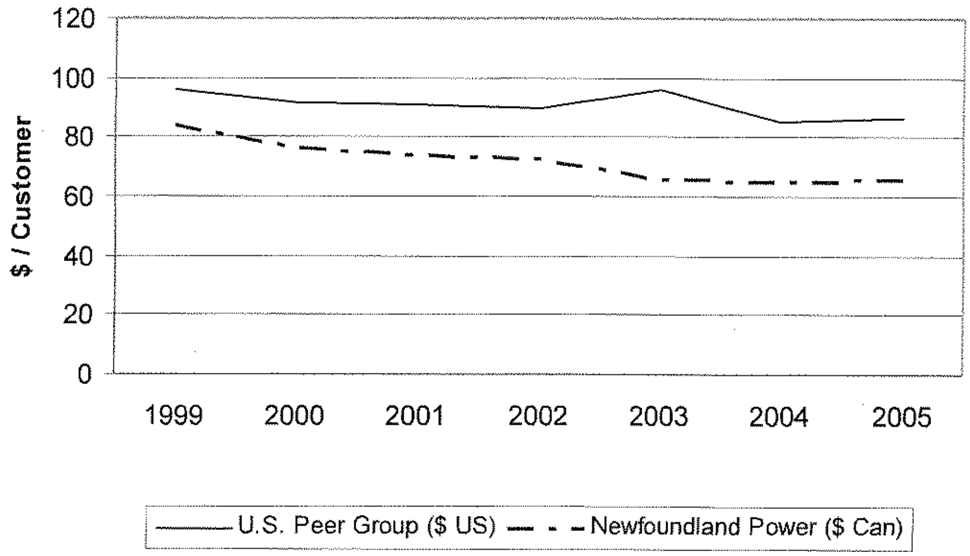
Appendix C

American (U.S.) Peer Group Composite Comparisons

Table of Contents

Measure **Page**

Total Distribution Operating Expense Per Customer
(2005$)

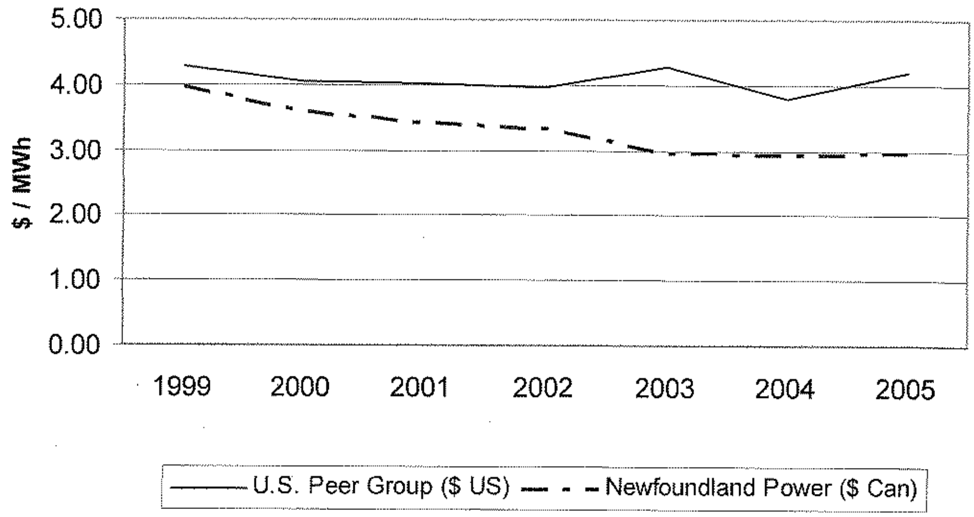


Year	U.S. Peer Group Composite	Newfoundland Power
1999	95.8	84.0
2000	91.8	76.3
2001	90.8	73.8
2002	89.9	72.9
2003	96.0	65.8
2004	85.1	65.3
2005	86.2	65.4

This measure represents the total cost of operating and maintenance for the distribution function, as defined under the FERC code of accounts, expressed on a per customer account basis. These costs substantially mirror the costs included in Direct Distribution OM&A as defined by COPE.

The Company has included 7 years of historic data for trending purposes. The trend shows a general downward trend for both Newfoundland Power and the U.S. peer group. The U.S. utilities' individual 2005 measures range from approximately $43 to approximately $160 per customer.

Total Distribution Operating Expense
Per MWh
(2005$)

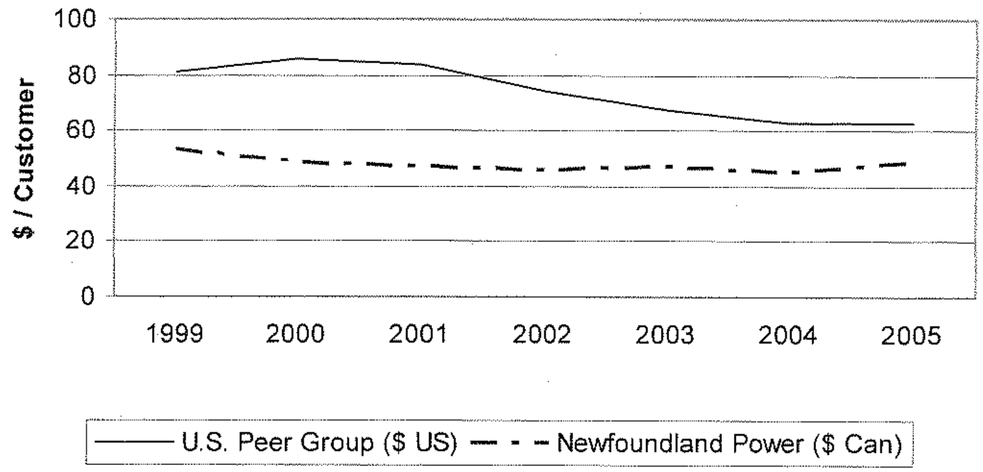


Year	U.S. Peer Group Composite	Newfoundland Power
1999	4.29	3.98
2000	4.06	3.59
2001	4.02	3.42
2002	3.96	3.34
2003	4.28	2.97
2004	3.80	2.93
2005	4.18	2.95

This measure represents the total cost of operating and maintenance for the distribution function, as defined under the FERC code of accounts, expressed on a per MWh of retail sales basis. The distribution operating and maintenance costs substantially mirror the costs included in Direct Distribution OM&A as defined by COPE. The MWh of retail sales includes the total MWh sales of electricity for retail rate schedules. It does not include sales for resale such as those to other distribution companies and retailers, nor energy interchanged through the power system (usually through transmission facilities).

The Company has included 7 years of historic data for trending purposes. The trend shows a general downward trend for Newfoundland Power and a relatively flat trend for the U.S. peer group. The U.S. utilities' individual 2005 measures range from approximately $2 to approximately $14 per MWh.

Total Customer Service Expenses
Per Customer
(2005$)

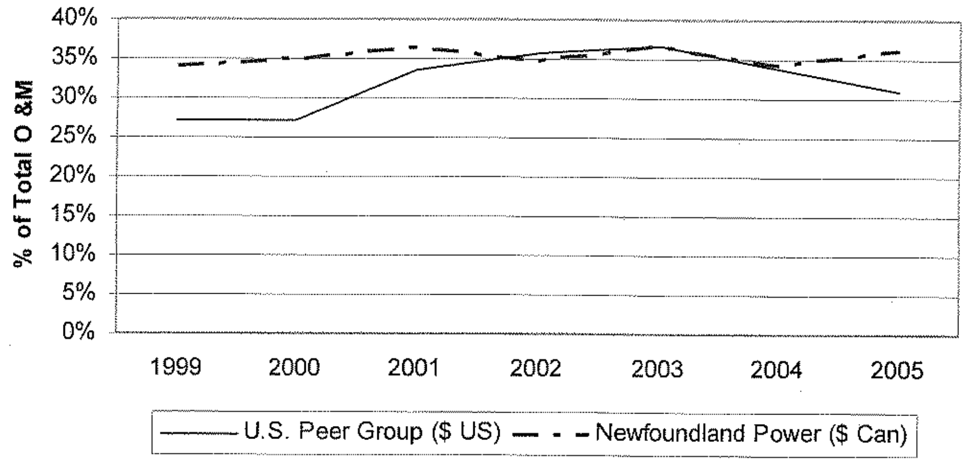


Year	U.S. Peer Group Composite	Newfoundland Power
1999	81.1	53.2
2000	86.0	48.5
2001	83.8	47.4
2002	74.3	45.6
2003	67.3	47.1
2004	63.2	46.2
2005	62.6	48.4

This measure represents the total cost of operating and maintenance for the customer accounting and customer service functions, as defined under the FERC code of accounts, expressed on a per customer account basis. These costs substantially mirror the costs included in Direct Customer Service OM&A as defined by COPE.

The Company has included 7 years of historic data for trending purposes. The trend for Newfoundland Power in recent years is relatively flat while the trend for the U.S. peer group is downward. The U.S. utilities' individual 2005 measures range from approximately $33 to approximately $145 per customer.

Total Administration and Other Operating Expense
Per Total Operating Expense
(Excluding fuel and purchased power, 2005$)



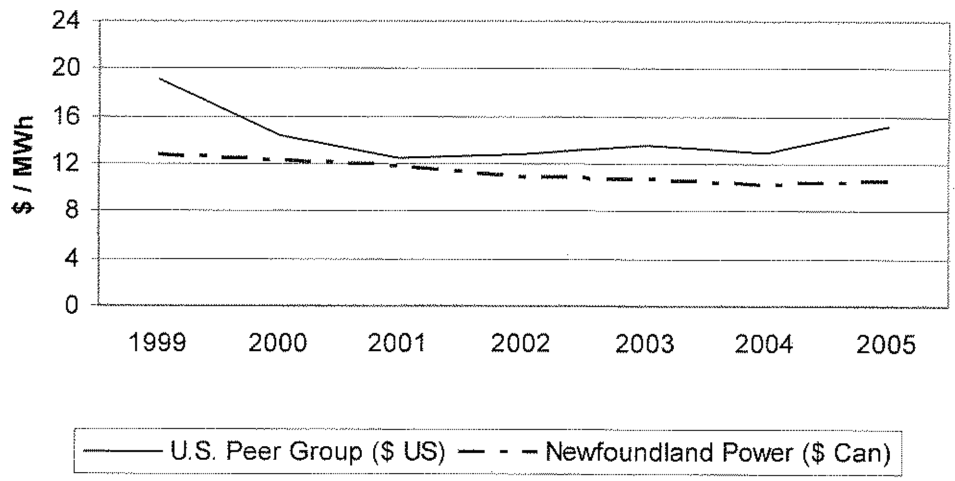
Year	U.S. Peer Group Composite	Newfoundland Power
1999	27.1%	34.0%
2000	27.2%	34.9%
2001	33.5%	36.4%
2002	35.7%	34.7%
2003	36.6%	36.8%
2004	33.7%	34.2%
2005	30.9%	36.3%

This measure is a ratio of the total administration and general expense to the overall corporate electrical operating and maintenance expense (excluding fuel and purchased power) as defined by the FERC code of accounts. The FERC administration and general costs are very similar to the Corporate Service OM&A as defined by COPE. The overall corporate operating and maintenance expense (excluding fuel and purchased power) is also very similar to the Corporate Overall OM&A as defined by COPE.

The trend line for the U.S. utilities shows an increase between 2000 and 2003 and a decline thereafter. The initial increase appears to reflect a dramatic reduction in production expenses (net of fuel and purchased power) that occurred between 1999 and 2001. The U.S. utilities' individual 2005 measures varied from approximately 12% to 53%.

The trend line for Newfoundland Power is relatively flat over the seven-year period.

Total Operating Expense
Per Energy Sold
(Excluding fuel and purchased power, 2005$)



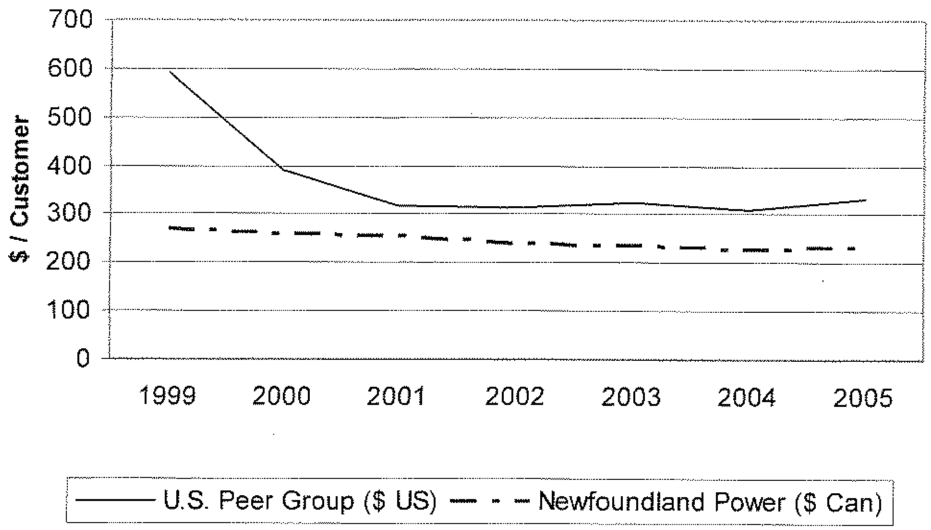
Year	U.S. Peer Group Composite	Newfoundland Power
1999	19.1	12.8
2000	14.3	12.3
2001	12.5	11.9
2002	12.7	10.9
2003	13.5	10.7
2004	13.0	10.3
2005	15.1	10.5

This measure represents the corporate electrical operating and maintenance expense (excluding fuel and purchased power), as defined by the FERC code of accounts, expressed on a per MWh of total energy sold basis. Total energy sold includes sales according to retail rate schedules, and sales for resale, such as sales to other distribution companies, sales to retailers, and energy interchanged through the power system (usually through transmission facilities).

The trend line for the U.S. utilities shows a significant decrease up to 2001 and a slightly upward trend since 2001. This reflects a dramatic reduction in production expenses (net of fuel and purchased power) that occurred between 1999 and 2001. The reduction in production expenses is likely due to industry restructuring or a change in policy for reporting such costs to FERC. The U.S. utilities' individual 2005 measures varied from approximately $5 to $39 per MWh.

The trend line for Newfoundland Power shows a decline over the seven-year period.

Total Operating Expense
Per Customer
(Excluding fuel and purchased power, 2005$)



Year	U.S. Peer Group Composite	Newfoundland Power
1999	590.53	269.73
2000	392.07	260.67
2001	318.82	255.96
2002	313.44	238.80
2003	325.14	236.20
2004	308.49	229.36
2005	333.62	233.08

This measure represents the corporate electrical operating and maintenance expense (excluding fuel and purchased power), as defined by the FERC code of accounts, expressed on a customer account basis.

The trend line for the U.S. utilities shows a significant decrease up to 2001. This decrease reflects a dramatic reduction in production expenses (net of fuel and purchased power) that occurred between 1999 and 2001. The reduction in production expenses is likely due to industry restructuring or a change in policy for reporting such costs to FERC. Beyond 2001, the trend is relatively flat. The U.S. utilities' individual measures varied from approximately 207 to approximately 594 in 2005.

The trend line for Newfoundland Power shows a decline over the seven-year period.

Appendix D

List of Companies Included in U.S. Utility Peer Group

Companies Included in U.S. Utility Peer Group
(2005 Information)

Company	Number of Customers	Sales (MWh)	% Production of Total O&M	% Transmission of Total O &M
Atlantic City Electric Company	709,371	10,080,109	33.8	1.7
Bangor Hydro-Electric Company	130,927	1,625,584	0.3	12.1
Central Hudson Gas and Electric Corporation	289,961	4,275,597	3.3	9.3
Central Illinois Public Service Company	368,090	10,621,946	0.1	9.3
Central Vermont Public Service Corporation	151,191	2,300,103	8.9	18.3
Unitil Energy Systems, Inc.	74,194	1,238,842	0.1	30.2
Delmarva Power & Light Company	505,821	14,101,673	5.1	6.9
Duquesne Light Company	586,050	13,896,547	0.0	4.6
Green Mountain Power Corporation	91,358	2,008,251	8.5	31.3
Illinois Power Company	605,282	15,860,576	0.2	11.9
Kingsport Power Company	45,960	2,096,027	0.0	4.5
Metropolitan Edison Company	530,060	14,008,539	-17.6 [1]	81.5 [1]
The Narragansett Electric Company	477,379	7,093,149	0.0	17.5
New York State Electric & Gas Corporation	859,877	15,127,234	1.2	10.5
Orange and Rockland Utilities, Inc.	216,988	4,316,469	1.9	8.2
Rockland Electric Company	71,533	1,738,407	0.0	4.0
The Union Light, Heat and Power Company	131,028	3,968,232	0.0	41.1
West Penn Power Company	702,801	20,070,803	1.0	21.9
Western Massachusetts Electric Company	204,150	3,113,996	0.6	13.4
Wheeling Power Company	41,294	2,144,090	0.0	8.4

[1] Anomalous results appear to be related to accounting issues.

Appendix E

CEA Policy Paper
Benchmarking Data in Regulatory Settings

Canadian Electricity Association
Policy Paper
Benchmarking Data in Regulatory Settings (BD/RS)

As approved by the CEA Executive Committee 14 October 2005

1.0 Overview

CEA and its members are seeking to improve their common frame work for utility performance measurement and best practices in order to ensure that the industry, shareholders, customers and rate-payers benefit from improved performance.

For many years, Canadian utilities have been participating, via CEA and other benchmarking organizations, in studies concerning the continuity of service, customer's satisfaction, employee safety and cost related indicators. The main purpose of these efforts was to improve the operational performance of the participating utilities. The process involved:

- Identifying participating utilities and the key performance indicators
- Gathering data on various performance indicators
- Conducting analysis to identify "best performers"
- Establishing working groups to validate "best performers" and determine "best practices" in the various business areas. In many cases this effort included a review of reporting practices to validate "best performers".

Since the main focus of these efforts was to improve operational performance, through the identification of utility "best practices", the data collection methods were not of sufficient quality for use in benchmarking for Regulatory purposes.

Regulators in Canada are increasingly requesting data and results from these benchmarking studies as a basis to assess electric utility company performance. While CEA and its members believe there are limitations to the use of benchmarking data in regulatory processes, CEA and its members are actively engaged with regulators to improve regulatory reporting in Canada.

2.0 Context

Many of the current indicators used are intended for operational purposes and as such do not require the degree of accuracy implicit in regulatory proceedings

Participation in benchmarking studies typically are voluntary. Regulatory actions using data for purposes it was not intended is likely to result in incorrect results and could therefore inhibit participation in benchmarking activities for the purpose of operational improvement. This would adversely impact the ability to identify best practices and the pursuit of performance improvement and ultimately will do a disservice to the ratepayer.

CEA believes it has a responsibility to develop the appropriate cautions concerning the use of non-verified benchmarking data in regulatory settings, and provide these cautions to members for their use when interfacing with regulatory bodies.

Given the inherent challenges in benchmarking with others, utilities have tended to limit the use of "peer group" benchmarking to discovery and identification of "best practices". For utilities, the relative ranking of the participants or the comparison of a utility to a composite has limited value and, when taken at face value, has little correlation to individual utilities' performance. The ultimate goal is performance improvement through informed decision making and the determination and utilization of "best practices".

By its very nature, "peer group" benchmarking is an extremely challenging undertaking. Attempts to account for unique operating and business environments are complex and require detailed information. This detailed information, while more than adequate for the "discovery" process which is at the heart of performance benchmarking, is often not of sufficient quality to be used in regulatory environments.

3.0 Policy

3.1
Policy 1
Appropriate benchmarking performance information (which is accurate, verifiable, and verified and includes the proper consideration, caveats, standardized interpretations and collection methodologies) will be developed by CEA for use in Regulatory settings. Participating CEA members commit to work towards providing data that meets these criteria, on a yearly basis, that will be used in the development of an agreed-to set of indices.

3.2
Policy 2
CEA members do not support a peer-to-peer approach when assessing a company's performance and especially to establish pass/fail criteria for breach and consequence, due to the complexity of identifying true "peers". This complexity is due to differences between companies' geography, climate, customer mix, growth rate, system age, resource mix, degree of interconnection, impact of significant events, and a range of other factors.

3.3
Policy 3
As a result of the complexity of "peer" benchmarking, trending the performance of an individual utility over time should be used as opposed to peer-to-peer benchmarking

3.4
Policy 4
CEA and its members will work cooperatively with regulatory authorities to ensure that indicators used in regulatory settings are accurate, verifiable and verified, and are meaningful. Through CEA's Councils, and in cooperation with members of CAMPUT, appropriate benchmarking indicators for assessing individual company performance over time will be developed.

3.5
Policy 5
CEA members will meet or exceed standards of data quality, integrity and consistency of reporting for these indicators

3.6
Policy 6
Improved productivity and performance result in significant benefits to companies, shareholders and customers. CEA therefore will continue to promote the use of benchmarking to identify best practices for performance improvement.

3.7
Policy 7
Only composite benchmarks deemed appropriate for regulatory environments, will be produced. Participants are cautioned that publication of metrics not identified as appropriate for regulatory environments in composite or other form in a regulatory forum or elsewhere may result in blocking further participation by that member or the termination of further CEA benchmarking on that metric.

3.8
Policy 8
CEA will subject all proposed new or modified indices to an agreed review process by the appropriate Council to ensure that the qualifying criteria are met.

4.0 Impact on CEA Activities

CEA Councils will develop as appropriate a short set of high-level indicators to be proposed as appropriate for regulatory purposes.

CEA Councils will provide direction to CEA data gathering bodies. This will include direction on the appropriate breadth and scope of data being gathered, and any changes required to the current indicators.

CEA's data gathering programs will establish standards for data quality, integrity and consistency of reporting.

5.0 Implementation

The CEA Policy on the use of Benchmarking Data in Regulatory Settings will be developed and refined by the Task Group.

The CEA Policy will be presented to Councils in August-September for review.

Once vetted by the Councils, the Policy will be submitted for approval to the CEA Executive Committee and Board of Directors in October and November, and, pending approval, will become public..

Beginning in fall 2005, the Councils will work with CEA data gathering programs to define the appropriate indicators for use in regulatory settings.

CEA Councils will provide strategic direction of data gathering bodies and activities beginning in 2006.

CEA 350 Sparks Street, suite 907, Ottawa, Ontario Canada K1R 7S8
Tel.: (613) 230-4102 · fax: (613) 230-9326 · info@canelect.ca
The voice of Canadian Electricity

350 rue Sparks, bureau 907, Ottawa, Ontario Canada K1R 7S8 ACE
Tél.: (613) 230-9263 · Téléc.: (613) 230-9326 · info@canelect.ca
La voix de l'électricité canadienne