National Overview of Regulatory Issues

CAMPUT 2001

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Foreword

This National Overview of Regulatory Issues is a formal vehicle for communication among CAMPUT members. The summary reports from member tribunals included in the National Overview reflect significant regulatory decisions made in each jurisdiction and emerging regulatory issues facing each member tribunal over the past year. We thank all the member tribunals for their contributions.

I would like to thank Deborah Emes and Jawed Aziz for their assistance in preparing this year's Overview.

We hope you find the Overview of interest and benefit to you. It is also available on the National Energy Board website. We would very much like to hear your comments and suggestions about the report and its content at our meeting in Saint John on September 11.

John S. Bulger
Chair, Regulatory Affairs Committee

CAMPUT 2001

Northwest Territories Public Utilities Board

The NWT Public Utilities Board as a result of industry and government changes, particularly the split with Nunavut, deregulation of the electric utility industry in Canada, the increasing commercialization of renewable energy technologies, and the need to reduce greenhouse gas emissions, commissioned a Strategic and Operational Review with respect to its future role. It was concluded that despite changing circumstances in the Northwest Territories, such as division, there will still be a need for a significant degree of regulation. However, because the workload can be highly variable, it was recommended that the board's mandate be expanded so as to make more effective use of the chairman and staff, both contracted and full time. Overall various stakeholders consulted in the preparation of the report strongly supported the continued presence of an independent Public Utilities Board.

The Government of the NWT has yet to act on the report, and meanwhile commissioned a review of Electrical Generation, Transmission and Distribution in the NWT. Included in the government's review is a suggestion, defying conventional wisdom, that regulation be eliminated entirely.

Meanwhile, the term of the full time Chairman was to expire March 31, 2001, at the same time the Northwest Territories Power Corporation indicated to its shareholder and to the Board that it was in the process of filing a General Rate Application to deal with all the issues arising out of division and the consequences of rising fuel prices, a significant element of its operating cost in an area where many communities rely on diesel generation for the provision of electrical energy.

The Chairman was approached and agreed to remain with the Board on a part time basis until the GRA could be reviewed, a hearing held, and a decision or decisions issued.

The Northwest Territories Power Corporation filed its application with the Board on May 9, 2001. Included in the application was a request for an order or orders:

a) determining a rate base for the Corporation's property that is used or required to be used in the provision of energy and related services to the public within the Northwest Territories ("NWT"), including the appropriate allowance for working capital, and fixing a fair return thereon for the Corporations's fiscal year commencing April 1, 2001 and ending March 31, 2003 ("Test Years");

b) determining the Corporation's revenue requirement for the Test Years for the provision of energy to the public in the NWT;

c) approving the Corporation's applied for Required Firm Capacity Planning Criteria for the Snare Yellowknife Zone, Diesel Communities and dual fuel generation communities;

d) approving the Corporation's applied for Alternative Energy Fund;

e) approving continuation of Rate Stabilization Funds, as well as various adjustments to the Funds, to mitigate the impact on rates of changes in fuel prices and deviations in hydro conditions from average water levels;

f) approving revised Terms and Conditions of Service.

It was anticipated several years ago that the Northwest Territories Power Corporation would continue to serve both jurisdictions after division, and a mechanism was developed to facilitate regulation by a "Joint Division" of the Nunavut and NWT Public Utilities Boards. However, the Government of Nunavut decided in November 1999 to form its own utility, the Nunavut Power Corporation. A formula for division of assets was approved by the Federal Government, and this should to some extent ease the burden on the Board with respect to the application now before it.

The Northwest Territories Power Corporation exists in a unique operating environment, operating 31 power plants in 27 communities. Extremely low customer densities, harsh climate and consequential logistical challenges, as well as the lack of an integrated transmission system sets the Corporation apart from most utilities, as does the fact that its generation is a mix of hydro, natural gas and diesel facilities. The unique environment has a profound impact in the Corporation's operations and ultimately on the regulator.

British Columbia Utilities Commission

In 2000/2001, the major issues facing the Commission resulted from high natural gas commodity prices and high electricity market prices outside of B.C. This combination of factors found natural gas consumers in B.C. looking to the Commission to mitigate high natural gas rates. Electricity producers in the province who had energy available to sell to the U.S. markets (e.g. BC Hydro, Cominco) were able to benefit from the high market prices. Key issues and challenges for the Commission in the future include mitigation of high gas commodity prices for consumers, reviewing BC Hydro's revenue requirements and rates once it is again fully regulated by the Commission, and dealing with issues related to high electricity market prices. The Commission is also reviewing the proposed sale of West Kootenay Power's generation assets to a subsidiary of two crown agencies, the Columbia Power Corporation and the Columbia Basin Trust.

Gas Utilities

In 2000, most B.C. natural gas utilities filed for large rate increases during the year, largely to recover the higher commodity cost of gas. Unprecedented high prices at Sumas during the winter of 2000/2001 caused the Commission to investigate the factors impacting the price and the validity of the index as a price setting mechanism. Following its review, the Commission concluded that a lack of capacity relative to demand at Sumas caused prices to disconnect from northeastern British Columbia and Alberta. The Commission determined that the impact of recently proposed pipeline and storage expansion projects in the Pacific Northwest should be assessed. In response to an offer by BC Gas, the Commission directed the utility to organize a stakeholder discussion on the regional natural gas resource balance, and submit a report to the Commission by June 29, 2001.

Natural gas rates are set on a forward test year based on the forecast cost of gas, and differences between the actual and the forecast cost of gas are recorded in deferral accounts. As the cost of gas has increased even faster than forecast, some utilities were accumulating large deferral account balances. Due to concerns about mid-year rate increases and the large BC Gas Gas Cost Reconciliation Account ("GCRA") balance, the Commission reviewed the method of establishing gas cost recovery rates for BC Gas and amortizing the GCRA balance.

Based on its review, the Commission established Guidelines for BC Gas in setting gas recovery rates and managing the GCRA Balance. BC Gas is to file quarterly reports and request gas cost recovery rate changes if the expected 12 month gas cost recovery revenue differs from the sum of expected gas costs for the same period plus the GCRA balance accumulated since January 1, 2001 by more than 5 percent. The Guidelines could also be appropriate for other provincial gas utilities.

The shutdown of a large methanol plant in Northwestern B.C. threatens the viability of Pacific Northern Gas ("PNG"), which serves the area. The Commission's Decision following a PNG revenue requirements hearing included a suggested minimum load retention rate for the methanol plant. The plant reopens in July 2001 for an unspecified period.

Direct gas sales in British Columbia have not yet penetrated commercial and residential markets. In response to requests from natural gas brokers/marketers, the Commission initiated development of an Agency, Billing and Collection Transportation ("ABC-T") tariff for BC Gas that would provide residential and commercial customers the option to purchase gas from non-utility suppliers. The targeted unbundling implementation is November 1, 2002.

British Columbia Hydro and Power Authority

The B.C. Hydro Rate Freeze and Profit Sharing Act which froze B.C. Hydro's rates from December 10, 1997 to March 31, 2000, was extended to September 30, 2001. The Commission is preparing to review BC Hydro's revenue requirements and rates for the period after the rate freeze. Meanwhile, in response to a Commission direction, BC Hydro has been submitting quarterly reports describing its export trade activities. Revenues from electricity trade were significant in 2000/01, but are expected to be lower in 2001/02 due to low reservoir levels and the implementation of price caps in California.

In response to high natural gas prices and high electricity export prices, a group of greenhouse operators approached the Commission in early 2001. They proposed to install small (1 to 10 MW) natural gas co-generation facilities and mitigate their gas costs by selling the power to BC Hydro or the export market, while using the waste heat and CO_2 in the greenhouses. In order to access the export market, they asked the Commission to establish terms and conditions and a rate for access to BC Hydro's distribution system. A brief hearing was held in May 2001, and a distribution access rate of 1 mill/kWh plus the cost of connection was established.

In February 2001, B.C. Hydro asked the Commission to review the obligation to serve industrial customers with self-generating capability that wished to sell their self-generated power at market prices, and take increased supply under BC Hydro's embedded cost rates. The Commission directed B.C. Hydro to allow transmission voltage customers with idle self-generation capability to sell excess self-generated electricity, provided they do not arbitrage between embedded cost utility service and market prices. B.C. Hydro is not required to supply increased embedded cost service to a customer selling its self-generation output to market.

B.C. Hydro's 1999 Integrated Electricity Plan identified the need for additional electricity supply to Vancouver Island by 2007. B.C. Hydro's preferred option appears to be a second co-generation plant (in addition to the Island Cogeneration Project at Campbell River). A new pipeline would deliver natural gas from the Lower Fraser Valley through Washington State and across the Strait of Georgia to Vancouver Island.

West Kootenay Power Ltd.

The Commission granted a CPCN in June 2000 to West Kootenay Power Ltd. ("WKP") to upgrade its aging transmission facilities, which would significantly improve the safety and reliability of electrical service.

In March 2001, WKP applied to transfer its four hydroelectric generation plants to a separate subsidiary, and sell the shares in the subsidiary to a joint venture of two crown agencies, Columbia Power Corporation and the Columbia Basin Trust. The Commission is reviewing the application through an oral public hearing.

Alberta Energy and Utilities Board

Electric Restructuring

The restructuring of the electric industry in Alberta requires the unbundling of the components of electric service. Generation and competitive retail service became fully deregulated as of January 1, 2001. However, transmission and distribution wires services remain fully regulated. Consequently, the Board was statutorily required to establish tariffs for these components of the electric industry for 2001. Additionally, the Board was required to establish a regulated rate option for a transition period, to allow residential, farm, irrigation and small commercial customers time to make choices as to competitive retailers. Below is a brief highlight of some of the decisions issued to assist in the transition to a restructured market.

a) Transmission Facility Owner (TFO) Tariffs set out the charges the TFOs (TransAlta, ATCO Electric and EPCOR Transmission) can recover from the Transmission Administrator (TA) and the terms and conditions of service pursuant to which the TA will use the TFO's facilities.

- Decision 2000-65 approved ATCO Electric's 2001-2002 TFO Negotiated Settlements. A more rigorous analysis was done in reviewing the settlement than customary. A staff member attended the negotiations to ensure that the process was fair and inclusive. Additionally, the Board examined a panel representing the applicant, and the EUB attached conditions to the decision.
- TransAlta's 2001 TFO Revenue Requirement was approved in Decision 2001-4. The Board determined that the opposition of a substantial number of interested parties to a settlement did not necessarily mean that the settlement was not just and reasonable. The Board conducted independent tests and concluded that the settlement was just and reasonable.

b) Transmission Administrator Tariffs are designed to recover the Transmission Administrator's (ESBI Alberta Ltd. [EAL]) internal costs; wire costs, which are the payments to wire owners for the use of their transmission lines; system support costs, including voltage control, system security, operating reserves, etc.; and other industry costs, including costs from the system controller.

- A number of modules were used to expedite the proceedings. Modules covered Phase I and II, terms and conditions of service, emergency provision of system support services and EAL's contribution policy.
- Decision 2001-35 approved three successful parties to EAL's Location Based Credits Standing Offer process, which pays incentives for the construction of electricity generation to relieve transmission constraints in specific areas at a cost less than building new transmission facilities.

c) Distribution Tariffs (DT) set out the charges that retailers pay for delivery of electricity to customers and the terms and conditions of service pursuant to which retailers and end customers will be serviced.

d) Regulated Rate Option Tariffs (RROT) combine the regulated delivery charges and the unregulated energy charges for smaller customers in Decisions 2000-73 and Decision 2000-74. Rates include the energy charge as prescribed by the Minister of Energy at a "soft cap" of 11 cents per kWh for the year 2001 with recovery of deferral balances in 2002.

e) As part of the restructuring of the electric industry, we are also experiencing asset rationalization. For example, in July 2000 the EUB approved the sale of TransAlta's distribution and retail businesses to UtiliCorp Networks Canada. In turn, UtiliCorp sold its retail business to EPCOR, a transaction that was also approved by the EUB in November of 2000. Furthermore, TransAlta has recently announced that it proposes to sell its transmission business as well, to focus solely on its core business of power generation. Similarly, ATCO recently announced its desire to sell its retail businesses for both natural gas and electricity.

Issues Respecting Natural Gas Distribution

a) Gas Cost Methodology

An issue concerned the methodology surrounding the gas cost recovery rate mechanism established in the late 1980s. Most residential customers continue to receive bundled service from their distribution utility, with only one competitive retailer serving the residential market. With prices for natural gas soaring in the winter of 2000/2001, questions were raised as to whether the regulated gas distribution utilities – ATCO Gas and AltaGas – should be hedging their natural gas purchases. The EUB convened a proceeding to look at this and other issues respecting gas cost methodology, with a decision to be issued later this year.

b) Gas Rate Unbundling

The Board initiated another proceeding to examine these cost allocations, with a decision to issue later this year.

c) In Decision 2000-85 the EUB clarified the principles to be followed with respect to unanimous NSPs, namely that:

- The settlement process must be fair and open to interested parties and sufficient information must be made available to understand the issues being negotiated. All parties should be provided an opportunity to participate and have their interests considered.
- Applicants have the onus of providing sufficient evidence and rationale to support the settlement.
- When presented with a settlement, the Board will not approve it in part if the agreement is contingent on the Board accepting the entire settlement. If the Board rejects the settlement, it will provide reasons outlining the areas causing concern.
- In determining the acceptability of a settlement, the Board will consider whether the agreement is in the public interest, is reasonable and fair to all interested parties, has a well-substantiated rational basis, and is complete and adequate to support the application.

d) Sale of Producing Properties Applications

In Decision 2001-46 dated May 29, 2001, the EUB denied applications by ATCO Gas for approval to sell certain producing properties, as the Board determined that the public interest was not met by the proposed sale.

NOVA Gas Transmission Ltd. (NGTL) Tariffs

Decision 2001-44 dated May 29, 2001 approved the Alberta System Rate Settlement, which established NGTL's revenue requirement and tolls for 2001 and 2002. This NSP was examined in a written proceeding and was found to be in the public interest.

Emerging Issues and Challenges

In addition to the issues discussed above relating to the restructuring of the electric and natural gas industries, the EUB anticipates a number of other challenges in the upcoming period, including:

- The development and optimization of transmission infrastructure to support new generation, which will raise issues respecting both siting and costs;
- The need to ensure the continuation of safe and reliable utility service in an environment of Performance Based Regulation (PBR) and asset rationalization;
- Managing the impact of costs resulting from 2000 electricity deferral accounts;
- Defining the role of the regulator in the new "deregulated" environment.

Saskatchewan Rate Review Panel

Background

In November 1999, the Saskatchewan Government created the Saskatchewan Interim Rate Review Panel (SIRRP) by Minister's Order. SRRP was mandated to advise on monopoly utility and insurance rates until July 2000. This Interim Panel conducted two rate reviews during its tenure and was assessed as being an effective and efficient mechanism by which government could receive objective advice regarding proposed rate changes.

The Saskatchewan Rate Review Panel (SRRP or the Panel) was subsequently established by Minister's Order in July 2000 to function as a permanent mechanism by which applications for changes in Crown monopoly utility and insurance rates could be reviewed. Each of the Crown corporations within the Panel's mandate (SaskEnergy, SaskPower and SGI AutoFund) operate under their own legislative authority and are governed by independent Boards of Directors.

Current Panel members are: Bob Lacoursiere (Chair), Jack Boan (Vice Chair), Tracey Bakkeli, Jo-Ann Carignan-Vallee, Sheldon Craig and Joan Meyer. Each member of the Panel has been appointed until July 25, 2002.

Mandate

In its general mandate, the Panel is instructed to conduct reviews and provide opinions on the fairness and reasonableness of proposed Crown corporation rate changes referred by the Minister of Crown Investments Corporation, considering the interests of the customer, the corporation and the public.

In conducting its reviews, the Panel is required to:

- receive a rate change submission from a Crown corporation;
- establish procedures for conducting the review and ensure that these procedures are made available to the public;
- engage the services of a consultant(s) to assist the Panel in its review of the fairness and reasonableness of the proposed rate change;
- make available to the public, prior to holding public meetings, the Crown corporation rate change submission, with the exception of commercially sensitive information;
- hold public meetings and provide appropriate notification to the public of the date and location of public meetings, including any rules for public participation and Crown corporation participation;
- provide members of the public with the opportunity to review and comment on the proposed rate changes to the extent reasonably allowed by the mandate of the Panel and by the schedule according to which the Panel is required to complete its work and provide its report to the Minister of Crown Investments Corporation;
- receive presentations of the consultant(s) or the Crown corporation, review any written submissions and receive comments from the public;
- prepare a report on the Crown corporation rate change submission for the Minister of Crown Investments Corporation after considering the material received from the Crown corporation, the consultant(s), the public and its own analysis:
- where the Panel determines the rate changes as proposed are fair and reasonable, recommend that the changes be implemented; or,
- where the Panel determines the rate changes are not fair and reasonable as proposed, recommend that the rate changes be adjusted providing reasons for this conclusion;

- provide its report respecting the proposed rate changes to the Minister of Crown Investments Corporation on a date set out in or within any time period after having received the rate change submission that is contained in the specific terms of reference for particular Crown corporation rate reviews; and,
- make its report available to the public.

Since it's creation in July 2000, the Panel has considered four rate applications, one each for SGI AutoFund and SaskPower and two for SaskEnergy. Thus far government has accepted and approved the Panel's recommendations for lesser amounts than the Crowns requested (see Appendix A). The one variation from Panel recommendations in the second SaskEnergy rate review was government subsequently mitigated the deficit for the Gas Cost Variance Account thus eliminating the need for a GCVA Recovery Fee.

Crown Rate Request - Summary	SRRP Recommendations
SGI – Auto Fund • An average increase to insurance premiums of 2.0%, equivalent to $8.3M, effective January 1, 2001 • Rates be adjusted by vehicle classification based on accident experience, ie. rate rebalancing within certain $ or % limits.	**SGI – Auto Fund** • Deny the average 2% overall increase. • Rate re-balancing should occur with limits reduced from those proposed. • Deny the re-establishment of a positive balance to the Rate Stabilization Reserve (RSR).
SaskEnergy (Application #1) • Increased gas consumption charges of 5.59 cents per cubic meter. • Increase natural gas delivery charges by an average of 2.4%. • Rate changes effective November 1, 2000, ie. beginning of the new gas year.	• Approve requested cost of gas increase. • No increase in delivery rates. • Delay rate change to December 1, 2000 (defers estimated $11.2M in gas costs to the next gas year ie. 2001-02).
SaskPower • An average increase in electrical rates of 3.25%. • Rate increase to be effective January 1, 2001. • Rate restructuring with substantial variation by customer class ranging from 0 to 10%.	• Allow rebalancing of some rates but within an overall increase of 2%. • New rates effective April 1, 2001 or later. • The maximum individual class increase be capped at 6%.
SaskEnergy (Application #2) • Increase gas consumption charges by 11.57 cents/cubic metre to 28.28 cents/cubic metre. • Begin to address the $80.2M deficit in the Gas Cost Variance Account (GCVA). • Rate change to be effective June 1, 2001 to October 31, 2002.	• Use a more up to date cost of gas forecast in the rate calculations; • Include additional revenues in the calculations • Apply a GCVA Recovery Fee (2.62cents/cubic metre) and a Cost of Gas Charge (24.39 cents/cubic metre) to yield a total Gas Consumption Charge of 27.01 cents/cubic metre.

The Public Utilities Board of Manitoba

Natural Gas Rate Issues

The dominant challenge facing the Board in 2000 was the rapidly increasing price of natural gas. In May 2000 the Board changed its methodology for dealing with rate increase applications moving away from the usual annual rate hearings to quarterly rate adjustments. In this new Rate Setting Methodology (RSM) the Board required the gas distributor to apply quarterly for an increase using the 12-month forward price strip.

The Board allowed a rate adjustment equal to 50% of the difference between the embedded price and the average price as per the forward strip. The Board had the option of varying the adjustment factor to any amount it deemed reasonable. The Board also had the option of conducting an oral or paper hearing.

The subsequent experience of the Board in light of extreme price increases over the winter has caused the Board to rethink its approach to price adjustments. It was argued that with simple fluctuations in the market, a 50% adjustment factor would provide rate stability and should be a fair reflection of the market. However, the presence of any significant price trend, up or down, the RSM causes a deviation from market prices, reduces price transparency and causes the Purchase Gas Variance Account (PGVA) which tracks the differences between the adjusted factor (50%) and market prices to grow significantly. In Manitoba the total gas costs which averaged $200M went to $500M and the PGVA went from $3M to $111M in a short period of time.

The Board has recently changed its approach. Quarterly adjustment to rates will still be done, however 100% of the difference between the embedded price and the 12 month forward strip price will be used.

The use of the 12 month strip versus the 6 or 3 month strip is being reviewed.

This process raised serious issues of price transparency and competition issues affecting brokers. When large amounts accumulate in PGVA the issue of liability and the principle of user pay can become a problem for the easy movement of consumers between the utility and gas brokers as well as the impact on new customers. The Board has approached these issues by establishing a special account to recover the PGVA from the customers who caused it. Customers can insulate themselves from the resulting fluctuations by using the budget payment plan or switch to a natural gas broker offering fixed price contracts.

About 50,000 of the Province's 220,000 residential gas customers are with brokers and 35-40% of total gas consumed, which includes commercial, is supplied by brokers.

Manitoba Hydro/Central Gas Merger

Centra Gas continues to be subject to full regulation even though all of its shares were acquired by the Crown Corporation Manitoba Hydro in mid-1999. It is expected that legislative changes will be made to rationalize the regulation of these two utilities in the future.

It should be noted that with the acquisition of the natural gas distributor there is now a significant monopoly, albeit Crown owned, in this province.

The Board is expecting an application from the parent company, Manitoba Hydro detailing the synergistic savings arising out of the acquisition of Centra Gas. At the acquisition hearing there were indications that this would amount to $12M to $15M annually. It was anticipated that this would arise from savings in the provision of common services such as billing and customer services, corporate services, meter reading, etc.

Manitoba Public Insurance (Auto)

Manitoba Public Insurance is a Crown owned monopoly of automobile no-fault insurance. The Board established a reserve fund to meet the financial requirements of claims arising from unusual circumstances such as winter storms, etc. The goal of the reserve fund was met and the company was able to reward its customers with a 16.6% rebate.

Manitoba Hydro

The Province of Manitoba currently tabled legislation mandatory, unified power rates across Manitoba. Currently, rural customers paying higher commodity rates in the first rate step only. Manitoba Hydro has identified this cost as $12M. The recovery of this cost will come from export rates. Initially, this came to the Board for approval and then was withdrawn when a legislative amendment was announced.

Manitoba Hydro customers continue to enjoy frozen power rates since 1997.

Ontario Energy Board

Mandate

The Energy Competition Act, 1998 defines the mandate of the Ontario Energy Board. The Board's roles and responsibilities are changing, as it makes the transition from a purely regulatory agency to one that will have major administrative responsibilities in the future electricity and natural gas markets.

During fiscal 2000-01, the Board carried out its traditional regulatory functions in the natural gas and electricity sectors, while addressing the major challenges of preparing for the opening of Ontario's new, competitive electricity market.

Performance

Electricity Regulation

Market Readiness

In September 2000, the Minister of Energy, Science and Technology announced he would set a date for opening the new electricity market when advised by the Independent Electricity Market Operator and the Ontario Energy Board that wholesale and retail participants were ready.

On January 2, 2001, Floyd Laughren, Chair of the Board, wrote to market participants that the Board would take responsibility for coordinating retail market readiness activities. Its retail market readiness plan, issued February 21, 2001, proposes one market opening date for both the wholesale and retail market, and a self-certification process for distribution utilities.

The Board's has determined that retail market participants can be ready for market opening by Dec. 14, 2001. Progress is being monitored and a self-certification plan was issued in April.

The Board's priority now is to ensure that participants are licensed, codes established and unbundled rates approved by the time the market opens. The government has announced that the market will open by May 2002.

Performance-Based Regulation

The Board has adopted a performance-based regulation (PBR) plan for electricity distribution utilities in order to expedite economic regulation and provide incentives consistent with a competitive electricity sector.

The PBR plan adopts a price cap for distribution rates, as well as minimum customer service performance standards and a consistent framework for service reliability monitoring. The price cap requires changes in distribution prices to be based on changes in input prices and a required annual 1.5 % productivity requirement.

Rates

By the end of March, the Board had received 122 applications. Thirty-nine applications were approved as of July 17 and the remainder will be considered this year. Most utilities are seeking a market-based return of 9.88 %.

In 2000, the Board carried out its first review of the Independent Electricity Market Operator's proposed annual operating budget and fees. In August it approved an initial revenue requirement for the year, and in January 2001 approved the revenue requirement for the current year.

Codes and Handbooks

The Board established several codes and accompanying rules handbooks, guidelines and procedural instructions for participants in the electricity market. The codes and handbooks listed below form the framework for the operation of the competitive electricity market.

- the *Affiliate Relationships Code*

- the *Electricity Retailer Code of Conduct*
- the *Retail Settlement Code*
- the *Standard Supply Service Code*
- the *Electricity Distribution System Code*
- the *Electricity Transmission System Code*
- the *Accounting Procedures Handbook*
- the *Electricity Distribution Rate Handbook*

In June 2000, the Board issued Chapter 10 of the Electricity Distribution Rate Handbook. The chapter outlines three ways distribution utilities can provide standard supply service: through a fixed reference price; by a third party; or by seeking an exemption to the Standard Supply Service Code.

The Board also commissioned a study on how to estimate the standard supply reference price. The resulting recommendations were used to set the initial fixed reference price and the ceiling price for standard supply service provided by a third party. The Board will update the study to ensure that prices accurately reflect conditions closer to market opening.

Electronic Billing Transactions

An advisory committee and working group developed a comprehensive set of standards for electronic business transactions. In practice these standards will enable electricity retailers and distributors to share customer and billing information efficiently, so that accounts can be settled quickly and accurately.

Licences

During 2000-01, the Board continued to license participants in Ontario's competitive electricity market. In all, the Board issued 36 licences to retailers, 28 licences to wholesalers, six to generators, and one licence to a distributor.

The Board has issued distribution licences to all municipally owned electricity distribution companies in the province, and to Hydro One Networks Inc. and Canadian Niagara Power Company Limited.

Licences have also been issued to 95 generators, 46 retailers, 36 wholesalers and the Independent Electricity Market Operator. In addition, the Board has issued licences to 27 gas marketers whose licences permit them to sell gas directly to low-volume customers.

Mergers, Acquisitions, Amalgamations and Divestitures

The Board is responsible for reviewing applications for mergers, acquisitions, amalgamations and divestitures in the electricity distribution system. The reviews protect the interests of consumers by ensuring that the new entities will be financially viable and provide a high level of service.

Of the 114 applications received, 105 had been approved by July 17, 2001.

Facilities

Under the *Ontario Energy Board Act*, companies must obtain a Board order granting leave to construct electricity transmission facilities for new electricity lines that carry a load of 50 kilovolts or higher and are more than two kilometres long. The Board reviewed and approved two major transmission projects.

The Board issued an order with conditions in January 2001 approving Hydro One's application to construct two transmission lines in the Ottawa area to connect with facilities being constructed by Hydro Quebec. The proposed lines will increase Ontario's interconnection capacity for electricity imports and exports by 1250 MW.

In the other transmission project review, the Board approved an application to build a new 240 kilovolt transmission line connecting TransAlta's proposed 440 megawatt cogeneration plant in Sarnia to the provincial electricity grid.

Gas Regulation

Rates

During the past year, market forces led to dramatic increases in the wellhead price of natural gas. The Board processed eight applications from natural gas distributors seeking to pass on the higher costs.

The Board reviewed two rate applications from Union Gas Limited, one from Enbridge Consumers Gas, and one application from Natural Resource Gas Limited.

One of the Union Gas applications included a proposal to unbundle its rates for upstream transportation and storage, and a proposal for a comprehensive, performance-based rate setting plan. The Board completed an oral hearing on the application in August 2000 and the decision was released July, 2001.

The application from Enbridge Consumers Gas concluded with acceptance of a settlement agreement in June 2001.

Proposed Gas Distribution Access Rule

The Board issued a proposed gas distribution access rule that establishes principles and standards for business transactions between gas distributors and marketers, and between distributors and their customers. Comments from stakeholders are being reviewed.

New Model Gas Franchise Agreement

In January 2001 the Board approved a new model franchise agreement for gas utilities and municipalities. Model franchise agreements allow the Board to streamline the regulatory approval process by bringing consistency to agreements across the province.

The agreement sets out terms and conditions that the Board will accept in franchise agreements. It is based upon a consensus reached by the gas utilities and the Association of Municipalities on all but two issues: permit fees and right of way fees. The Board decided that municipalities could charge cost-based permit fees but should not charge fees for use of municipal right of ways and road allowances.

Subsequently, the government passed Regulation 61/01, which prohibits municipalities from collecting user and permit fees from gas companies and electricity utilities.

More than 60 interim extensions to municipal gas franchise agreements were approved pending approval of the new model franchise agreement.

Review of Regulatory Process

In 2000 the Board began a review of how it might streamline its regulatory processes. After consulting with stakeholders, the hearing process review committee recommended pilot projects in three areas: pre-filed evidence requirements, issues list development, and guidelines for participation in alternative dispute resolution.

Bill 57 amends the Ontario Energy Board Act as follows:

- Gas storage areas are to be designated by an order of the Board rather than by a regulation made by the Lieutenant Governor in Council on the recommendation of the Board, and
- The director of licensing is given the authority to impose penalties of up to $10,000 a day for contravening licence conditions or Board rules, or for operating without the proper licence. Persons who are being penalized have the right to request a hearing before the Board.

Emerging Issues and Outlook

Issues that the Board will be dealing with in the coming year include the following:

- Market Readiness - Will utilities have the systems and processes to provide standard supply service, calculate settlement costs, produce unbundled bills, change suppliers, and carry out electronic business transactions?
- Consumer Information - How can the Board, by providing useful information for consumers, contribute to a smooth transition to a competitive electricity market?
- Review of Regulatory Process - How can the Board streamline information requirements and regulatory processes?
- Second generation electricity PBR - How should the Board design its second generation PBR plan, taking into account the need for a price adjustment mechanism, demand-side management, and service quality and reliability standards?
- Gas Utility Regulation - How might the Board's responsibility with respect to gas utility rate regulation in Ontario evolve with the shift to performance-based regulation? What standards and principles for business transactions should be applied to marketers and utilities?
- Market Surveillance - How might the Board fulfill its obligation to jointly monitor electricity markets with the Independent Electricity Market Operator?

Régie de l'énergie du Québec

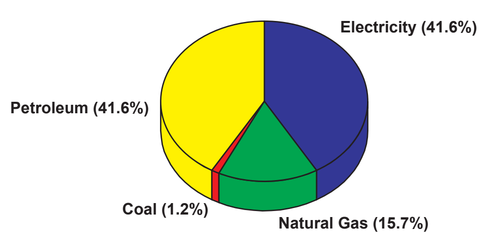
Introduction

La Régie de l'énergie is an arm's-length and self-financing agency operating as a quasi-judicial body or according to the principles of due process, based on the nature of the application. The Régie sets and amends electricity transmission and distribution rates and conditions, and sets rates and conditions for the supply, transportation, delivery and storage of natural gas. The Régie also reviews complaints from consumers of electricity and natural gas, and monitors the prices of petroleum products and steam.

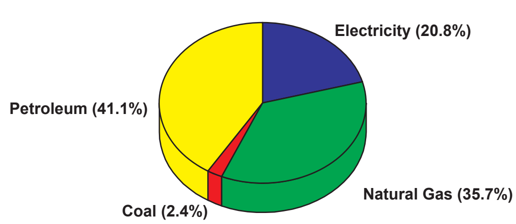
Energy Consumption

Electricity represents 42% of energy consumption in Quebec, compared with 21% in the rest of Canada. The situation is the reverse for natural gas, which accounts for 16% of consumption in Quebec, as opposed to 36% in the rest of Canada.

Energy consumption in Quebec - 1999



Energy consumption in the rest of Canada - 1999



Market Structure

There is an extremely marked concentration of distribution activities in both the electricity and natural gas sectors. Hydro-Québec controls 97% of distribution in Quebec, with municipal and private systems distributing 3%.

In the natural gas sector, Société en commandite Gaz Métropolitain (SCGM) delivers 97% of volumes sold in Quebec, and Gazifère Inc. (Gazifère) of Hull delivers 3% of volumes.

Review of Activities

Electricity

Determination of electric power transmission rates [Hearing on application for changes to electric power transmission rates (R-3401-98)]

In the electricity sector, the Régie is gradually exercising its powers in its new areas of expertise, specifically, pricing, supply conditions and marketing programs. The Régie is currently reviewing the application for electricity transmission rate changes filed by Hydro-Québec's transmission division, TransÉnergie, on August 15, 2000.

TransÉnergie is requesting that the Régie authorize for 2001 a revenue requirement of $2.6 billion, a rate base made up of $15 billion in assets for 2001, and a 10.6% rate of return on shareholders' equity, and that the Régie approve TransÉnergie's transmission rates and conditions.

There are eleven intervenors from Quebec and five from the rest of Canada and the United States.

Hearing on Hydro-Québec's service conditions (Bylaw 634) (R-3439-2000)

In Decision D-2000-95, May 26, 2000, the Régie asked Hydro-Québec to file proposals on three matters: the service contract and the related obligations, metering and billing, and terms of payment and credit and collection policies.

Application to renew its Electrotechnology Implementation Support (EIS) program for business customers (R-3453-2000)

In Decision D-2001-65, March 6, 2001, the Régie authorized the renewal of an EIS program. Hydro-Québec is required to file a triannual monitoring report and an annual progress report on specifying the degree to which set objectives have been attained and, where necessary, changes made to the initial objectives.

Application to approve an interruptible power II program (R-3455-2000)

In Decision D-2001-110, April 24, 2000, the Régie authorized the implementation of an interruptible power II program and the rates proposed by Hydro-Québec. Under the program, Hydro-Québec Distribution may interrupt the power of participating customers, by buying back the power, in exchange for which the customers receive monetary compensation from Hydro-Québec Generation.

Natural gas

Implementation of incentive-based measures or mechanisms ("PBR") (R-3425-99)

In Decision D-2000-183, October 5, 2000, the Régie authorized the agreement signed August 21, 2000 by SCGM and a group of intervenors participating in a negotiated agreement process (NAP) initiated May 19, 1999.

This five-year agreement provides for the annual setting, within the framework of a NAP, of the distributor's revenue cap and revenue requirement subsequently filed for the Régie's authorization. Any favourable variances between those two amounts, before the beginning of the fiscal year, will be shared in a ratio of 52.5% for shareholders and 47.5% for customers, with 40% of the amount allocated to customers reinvested in an energy efficiency fund (EEF). At the end of the fiscal year, if authorized rates generate overearnings, customers would recover 66 2/3% in the following year's rates.

The agreement provides for the possibility of an incentive 400 basis points greater than the authorized rate of return for two consecutive years. Various terms apply in the event that the revenue cap is exceeded. The agreement also stipulates that the incentive is conditional on the distributor's attainment of set objectives for service quality indicators.

Energy efficiency programs (R-3444-2000 for SCGM and R-3446-2000 for Gazifère)

In Decision D-2000-211, November 15, 2000, the Régie authorized the implementation of the energy efficiency plan filed by SCGM, generating a net return to users of $4.7 million as measured by the total resource cost test. Energy savings, calculated over the lifetime of the efficiency measures, are approximately 98 million cubic feet of natural gas.

In Decision D-2001-55, February 19, 2001, the Régie authorized the business plan and energy efficiency program filed by Gazifère.

In both cases, the Régie approved a revenue loss adjustment mechanism.

Rate unbundling – SCGM (R-3443-2000)

In Decision D-2001-78, March 16, 2001, the Régie authorized the rate structure and provisions filed by SCGM for unbundling all main components, i.e., gas supply, fuel gas, transportation, load balancing and distribution services. Unbundling will allow for competition in some services traditionally provided by the distributor. As of October 1, 2001, customers may deal directly with third parties for transportation and load balancing services.

Petroleum products

In Decision D-2000-141, July 21, 2000, the Régie renewed for three years Decision D-99-133 setting gasoline and diesel fuel retailers' operating costs at 3 cents per litre.

Also, a hearing on the inclusion of operating costs of gasoline and diesel fuel retailers in the National Capital Region was initiated by an application filed in December 2000 (R-3457-2000).

The Régie posts a weekly bulletin on petroleum product prices in Quebec on its website, providing consumers in each region of Quebec with information on average prices at the pump, the minimum prices estimated by the Régie, and changes in retail prices for gasoline, diesel fuel and heating oil.

Priorities for 2001-2002

The Régie will continue its work on approving an electricity transmission rate and reviewing Bylaw 634 respecting the conditions governing the supply of electricity by Hydro-Québec. The Régie will begin reviewing the revenue requirement for Hydro-Québec's distribution activities.

The Régie will review the measures adopted by natural gas distributors to mitigate fluctuations in commodity market prices to protect consumers.

The Régie will probably review an application by SCGM concerning natural gas supply for its franchise from the Sable Island, Nova Scotia gas basin.

The Régie will also analyse the impact of measures in the Act respecting the Régie de l'énergie on commercial practices in the gasoline and diesel fuel retail business.

Conclusion

The Régie will stay abreast of best practices in an effort to streamline the regulatory process and promote regulation based on distributors' performance improvements and consumer satisfaction.

The Régie will build on its close ties with the Ontario Energy Board, Mexico's Energy Board and its US partners in the National Association of Regulatory Utility Commissioners. The Régie is a member of advisory boards of various regulatory and energy research centres, and will also continue playing an active role in CAMPUT (the Canadian Association of Members of Public Utility Tribunals).

Internationally, the Régie will continue its efforts to develop close ties with regulators who attended the World Forum on Energy Regulation held in Montreal in May 2000.

Board of Commissioners of Public Utilities of the Province of New Brunswick

In the past year, the Board has continued its regulatory activities with respect to the natural gas distribution system in New Brunswick. Following the written decision regarding the Codes of Conduct in March 2000, the Board issued an Addendum for a number of issues which required further clarification. An important consideration in this Addendum was the change in measurable billing units from volume to gigajoules. This change promoted consistency between the provinces of Nova Scotia and New Brunswick avoiding customer confusion.

In June 2000, the Board issued its decision on the Permits to Construct Pipelines for the purpose of gas distribution. The decision allowed for the construction of extra-high pressure lines and high pressure lines in a number of communities until December 2001. The construction of infill lines in the municipalities is permitted to be carried out throughout the five year development period, until 2005.

Since the issuance of the decision, EGNB has met its goal of installing the extra-high pressure and high pressure piping within the four municipalities of Fredericton, Oromocto, Moncton and Saint John. Infill lines are currently under construction in these areas.

As part of the decision process, the Board gave the applicant, EGNB, and the Union of New Brunswick Indians (UNBI) some time to develop a protocol on:

- The design of a survey on medicinal plants, plants for traditional uses and archaeology;
- The allocation of $15,000 to UNBI for their use in the conduct of the surveys;
- The longer term inclusion of UNBI in the development of the natural gas industry;
- The notice to be given to UNBI if any sites of archaeological significance to the aboriginal people are found during construction.

During pipeline construction in Moncton, the discovery of an archaeological site prompted the MAWIW Council of First Nations (not considered part of UNBI) to request a stop work order because EGNB had not met its commitments of the protocol. Upon further investigation, the site was deemed to be not a "significant" site and construction has since been completed. While the "stop work order" was not formally issued by the Board, the parties involved have been instructed to revise the protocol and submit a consensus document. The Board will formally respond to the revised protocol.

In June 2000, the Board issued its Decision with respect to the Rates and Tariffs for natural gas distribution. During the EGNB hearings on Rates and Tariffs, the Board decided that the matter of cost awards to intervenors should be dealt with through a written process. Parties were invited to submit their positions with respect to:

i) What principles should be applied in determining whether costs are awarded:

ii) What guidelines should be applied with respect to assessment of costs; and

iii) What procedures should be used for fixing or taxing costs.

The Board received interventions from several parties, including the Applicant and the Union of New Brunswick Indians. Following a detailed review of the information submitted and the practices in other jurisdictions, the Board concluded that "it will exercise its discretion to award costs sparingly and it will consider the specific interests of the party requesting costs as well as the interests of the customers who will ultimately be required to pay the costs through rates". Further, if it (the Board) "finds that a cost award is justified, it will also decide whether the costs submitted should be fixed by the Board or taxed."

To assist any party wishing to make application for intervenor costs, the Board issued broad guidelines:

i) When applying for a cost award, the applicant should demonstrate how it made a material contribution to a better understanding of the issues by the Board.

ii) Any party who submits an application for costs should attempt to justify the request for costs on the basis of the public interest. This justification is most important where:

- The intervention was not to protect a direct or pecuniary interest,
- The intervenor has funding from other sources, or could have been reasonably expected to obtain funding from other sources,
- The intervenor failed to make reasonable efforts to negotiate, and
- The costs of intervention requested are incremental to the normal operating costs of the intervenor.

The Board is currently engaged in hearings for an application from NB Power, the crown owned power utility. Under the Public Utilities Act, NB Power must bring forward any projects involving a capital expenditure of $75 million dollars or greater. The Board will issue a recommendation to the utility based on the outcome of the review and hearing of the application.

NB Power, in its application, requested a generic hearing to address three questions:

i) Is it reasonable to believe that NB Power will require the electricity presently generated by Coleson Cove and/or Point Lepreau or replacement facilities in the future?

ii) What are the relevant issues to be reviewed during any subsequent specific generating facility upgrading and/or maintenance hearing?

iii) What is the nature and scope of the evidence that NB Power should provide for those hearings?

The generic hearing, a "new" approach for the Board, held in the week of June 4, 2001, allowed the intervenors to ask additional questions of the applicant regarding their pre-filed evidence on the questions provided. The specific hearings will be held at a later time and will deal with each facility independently.

In addition to the NB Power hearings, the Board has received an application from the Potash Company of Saskatchewan (PSC) for a local gas producer franchise which would allow PCS to apply for permit to build a pipeline for the purpose of serving its facility in Sussex, NB. The specific hearing will be held in July, 2001.

To accommodate this increased level of activity for the Board, the Commission has undergone a significant expansion in terms of staff complement and has moved to larger premises. Given the proposed projects by NB Power and the expanding natural gas market, it is unlikely that the Board will see any decrease in activity in the next year.

In addition to this anticipated increase in workload, the Board's role and mandate in the restructuring of the electric power industry in New Brunswick will expand significantly as outlined in the recently released government White Paper on the Energy Policy (February 2001). Specific functions for the Board will be with respect to setting transmission tariffs, determining if stranded costs exist and establishing exit fees for anyone leaving the existing generation system.

One of the first steps in the implementation of the energy policy is the establishment of the Market Design Committee. The Committee, comprised of representatives of government, private sector and non-government organizations, will be tasked with making recommendations on the structure and rules of a competitive wholesale and large industrial electricity market. The Board has representation on this Committee which will meet weekly to meet the deadline for its recommendations to the Government by March 2002.

Prince Edward Island Regulatory and Appeals Commission

Background

The Prince Edward Island Regulatory and Appeals Commission (IRAC) was established in 1991 with the amalgamation of the former Public Utilities Commission, Land Use Commission, and the office of the Director of Residential Rental Property. The Commission has partial or full responsibility for some 25 Provincial Acts. Regulatory functions include: Petroleum pricing, Municipal Sewer and Water utilities, Lands Protection Act, and Maritime Electric Company Limited Regulation Act. Appeal functions relate to the Planning Act, Revenue Administration Act, Rental of Residential Property Act, Revenue Tax Act, and Real Property Tax Act.

2000-2001

As is the case in many jurisdictions the rising cost of fuel has had a dramatic impact on energy prices and services on Prince Edward Island. This is especially true in the electricity and gasoline/home heating fuel markets.

Electricity

This year brought additional changes to the already de-regulated electric energy system on Prince Edward Island.

The high cost of on-Island, fossil fuel based generation has been a consistent challenge for Prince Edward Island, resulting in some of the highest electricity costs in Canada. Over the past twelve months, rising costs and shutdowns at Point Lepreau placed significant financial pressure on Maritime Electric Company, Limited (MECL).

In 1976 the Island system became interconnected with New Brunswick Power through a submarine power cable, and since that time much of the power utilized by MECL is obtained from NB Power. (The company is a participant in Point Lepreau.)

In 1994 a significant step was taken with regards to regulation of the industry. The Government of Prince Edward Island, in agreement with Maritime Electric Company, Limited, enacted legislation, which virtually eliminated traditional regulation of the Company, but set Island power rates at 110% of NB Power rates. (The company was given until 1998 to meet the 110% target)

The Island Regulatory and Appeals Commission maintained a monitoring function and the legislation included protection for Maritime Electric Company, Limited from subsidy of power rates in New Brunswick.

This past year Maritime Electric Company, Limited made application under the legislation to recover what they considered a subsidy of NB Power rates, namely the decision of the New Brunswick Government to write down its investment in NB Power by $450 million after NB Power decided to write off $450 million of accounting value related to Point Lepreau. Maritime Electric Company, Limited increased rates 4.53 percent January 1st to compensate for the claimed subsidy.

A Public hearing commenced in late January, 2001. At the hearing MECL supported the 4.53% increase in rates. The government intervened. Dispute arose over what provision of the Act permitted MECL to seek the rate adjustment. The Commission issued an Order that permitted the application to proceed, but that decision was appealed to the Supreme Court by the Intervener. Prior to any ruling from the Court, Maritime Electric Company, Limited and the Government of Prince Edward Island again agreed on changes to the legislation.

An Act to amend the Maritime Electric Company Limited Regulation Act was passed in May. As a result, the proceedings in the Supreme Court were stayed and the application to the Commission was withdrawn.

The legislation has several provisions. It permits MECL to collect the 4.53 percent increase in rates, but requires it to use the increased revenue collected between January 1, 2001 and April 1, 2002 to reduce rates the following year. The Legislation also permits the adjustment of base rates through regulation. The regulations are now being developed, and the final implications for the Commission are not known.

The application regarding subsidy was the first time MECL has appeared before the Commission in six years, and the hearing was not completed.

Natural Gas

Results of an exploration well for Natural Gas drilled in eastern PEI over the past year have not been announced.

The Electric Utility has also expressed interest in constructing a natural gas fired generation facility on the Island, which would require the development of a gas pipeline to the province.

Petroleum

As the only jurisdiction in Canada to regulate fuel prices the rapidly changing energy costs highlighted the Commissions activities over the past year. The industry opposes regulation and has made representations to the Commission encouraging de-regulation or the adoption of a pricing system based on rack prices. Public input is mostly in response to the substantial increase in profits of the major oil companies and the impact of rising prices on individuals. The present crude-based pricing model has been in use for 13 years, and the Commission is currently analyzing the system with a view to possible streamlining.

Nova Scotia Utility and Review Board

General

The Nova Scotia Utility and Review Board was created in December, 1992 by proclamation of the Utility and Review Board Act, which combined the Board of Commissioners of Public Utilities, the Nova Scotia Municipal Board, the Expropriations Compensation Board and the Nova Scotia Tax Review Board. The Board has a very broad mandate encompassing a number of Acts. Its activities fall under two categories: regulatory and adjudicative. On the regulatory side, the Board regulates electric and water utilities, natural gas distribution and pipelines, licenses public passenger carriers, approves Facility automobile insurance rates and approves Halifax - Dartmouth Bridge Commission fares. Since April 2000 the Board has conducted hearings relating to gaming control, liquor control and film classification.

Electricity

The largest utility regulated by the Board is Nova Scotia Power Inc. (NSPI). It provides 97% of the generation and 95% of the distribution of electricity in the province. It is the successor to the Nova Scotia Power Corporation which was privatized in 1992. As of January 1, 1999, NSPI became the principal subsidiary of NS Power Holdings Inc., known as Emera Inc. since July 2000.

To date there have been no moves to restructure the electricity industry in Nova Scotia and the Board continues to regulate NSPI on a cost of service basis. While deregulation is not imminent, the provincial government has been engaged in a public consultation process over the last several months called the Energy Strategy Review. In a paper issued in March, 2001 entitled “Powering Nova Scotia’s Economy, A Public Discussion Paper on the Province’s Energy Strategy”, the government indicated that electricity restructuring will form part of the review.

NSPI has not filed for a rate increase since 1995. In March, 1996 the Board granted the Company a 1.8% average rate increase. However, 2001 has not been without activity on the rate-making front.

In a decision dated July 9, 2001 the Board denied an application by NSPI “for approval of a process under which flexible, market-based, integrated energy solutions packages may be developed, approved and offered to customers”. NSPI sought authority to implement a “rapid approval” process for rates which were to be targeted to certain customers and “market segments” based on three considerations: whether the specially tailored rate would serve to retain customers, or would promote load shifting from peak to off-peak periods or would promote increased usage in off-peak periods. The rates were to be associated with appropriate products and services and were to exceed the incremental cost of providing the “energy solutions packages”. NSPI indicated that it would likely offer more than 20 such rate packages in the first year after receiving Board approval. The proposed approval process contemplated deemed approval by the Board 20 days after filing unless the Board requested additional information in which event the rate would go into effect five days after the information was supplied.

While the Board recognized that there can be a place for load retention rates in limited circumstances, and indeed approved a load retention rate last year for customers who are considering an alternate energy supply of at least 2,000 kVA, and that there is a place for well-structured time-of-day rates in order to encourage load shifting, it found the proposal objectionable not only in terms of the approval process, but even more so because of the discriminatory aspects of the proposed rates. As an example, NSPI suggested that it might offer lower rates to residential customers in areas where natural gas is being introduced than to customers in areas where natural gas will continue to be unavailable. The

Board observed that “NSPI appears to want the flexibility of a non-utility business while continuing to enjoy the advantages of a regulated monopoly. The Board simply does not find sufficient justification for this degree of pricing flexibility at this time.” The Board suggested that NSPI consider extending existing time-of-use rates to additional customer classes.

On March 16, 2001, the Board approved an interim Code of Conduct for NSPI to govern its relations with corporate affiliates. The Code focuses on ensuring that unregulated subsidiaries of the holding company are not subsidized by the customers of NSPI. It comes into force on September 16, 2001.

Natural Gas

As indicated in last year’s report to CAMPUT, the Board awarded a distribution franchise in November, 1999 to Sempra Atlantic Gas Company (Sempra), a subsidiary of Sempra Energy, a California-based energy company with 2000 revenues of $7 billion (US). The award was confirmed by the Governor in Council in December, 1999.

Sempra commenced its pipe-laying program in October, 2000 and laid approximately 16 km of distribution pipe in the Burnside Industrial Park, Dartmouth and in Crichton Park, a residential area of Dartmouth, before ceasing pipe-laying operations for the winter. These mains have not yet been connected to the Maritimes and Northeast Halifax lateral and Sempra has not yet applied for a license to operate.

In a decision released May 3, 2001, the Board approved Sempra’s Initial Tariff, including its multi-year rate plan and terms and conditions of service.

On June 29, 2001 Sempra applied to the Board for an order “consenting to the surrender of its Gas Distribution Franchise, or, in the alternative, approving amendments to its Franchise”. Sempra stated in its application that there have been material changes in circumstances beyond its control, in particular its inability to install pipes under provincial secondary roads and road shoulders, the unprecedented and unforeseeable level of volatility in energy prices “and its negative impact on the company’s margins” and the proposed operation of the Point Tupper Lateral at a pressure materially less than that relied upon by the company in formulating its plan to service areas off that Lateral.

The Board issued Directions on Procedure on July 6, 2001. It noted that the amendments proposed by Sempra “are substantive and are not in conformity with existing Regulations”. The Board decided to invite new applications to construct and operate gas delivery systems in the Province in addition to hearing Sempra’s application. It has received a total of 14 notices of intention to apply for franchises, 10 for specific areas of the Province, and four for province-wide franchises. Among those filing notices of application for province-wide franchises were AltaGas, Enbridge and SaskEnergy. Applications are due August 30, 2001 and the hearing is scheduled to commence on October 15, 2001.

Board of Commissioners of Public Utilities for Newfoundland and Labrador

Introduction

The Board is an independent quasi-judicial regulatory agency appointed by the Lieutenant Governor in Council and operates primarily under the authority of the Public Utilities Act, R.S.N., 1990. The Board is comprised by statute of three full-time Commissioners and up to six part-time Commissioners. The Board has a staff complement of ten, comprised of six administrative staff and four regulatory staff. The Board is fully funded by assessments upon industries regulated and receives no funding from the Provincial Government.

The Board administers the following Acts, or parts thereof:

- The Electrical Power Control Act,
- The Public Utilities Acquisition of Land Act,
- The Automobile Insurance Act (part),
- The Motor Carrier Act,
- The Motor Vehicle Transport Act of Canada,
- The Expropriations Act, and
- The Public Utilities Act.

Electric Utilities

The two main electric utilities operating in the Province of Newfoundland and Labrador regulated by the Board are Newfoundland Power Inc., an investor-owned utility, and Newfoundland and Labrador Hydro Corporation, a crown corporation. The Board receives numerous reports on a regular basis from the utilities on their operations, and the Board uses these reports in its continued oversight of the electric utility industry in the Province.

Significant items coming before the Board this year include:

Newfoundland & Labrador Hydro,
P.U. 25(2000-2001)
P.U. 38(2000-2001)

On November 19, 1999, Hydro applied to adjust the rates that the utility charges to its Island Industrial customers. In Order P.U. 23(1999-2000) the Board set interim rates for this class of customer for the period January 1, 2000 to November 30, 2000 and ordered the utility to file an updated cost of service study reflecting 1999 actual operating and financial results. Following review, the Board decided that the information received was not appropriate for the finalization of rates for industrial customers and that these rates should not be finalized in isolation of rates charged to the other customer classes of Hydro. Hydro was therefore ordered to file a general rate application no later than May 1, 2001 along with a critical path of milestones and activities leading up to the application and bi-weekly reports on the progress in meeting these timelines. The filing date was later amended in Order P.U. 38(2000-2001), at the request of Hydro, to May 31, 2001.

P.U. 31(2000-2001)

On October 16, 2000 Newfoundland & Labrador Hydro filed its 2001 Capital Budget for approval. Following a public hearing, capital expenditures totaling $54,681,000 were approved.

Newfoundland Power Inc.
P.U. 7(2000-2001)

On May 25, 2000, Newfoundland Power applied to adjust its schedule of rates for the impact of the Rate Stabilization Adjustment (RSA) and Municipal Tax Adjustment (MTA). The RSA is designed to ensure stability in electrical energy costs despite variations in fuel prices. The MTA is a flow through of taxes charged by municipalities in which the company operates. The application of these two adjustments resulted in an overall reduction of energy costs to consumers of 1.1%.

P.U. 24(2000-2001)

On August 15, 2000, Newfoundland Power applied for approval of its: 2001 capital budget with forecasted expenditures of $39,109,000; rate base for 1999 of $505,688,000: forecasted average rate base for 2000 of $518,724,000; and forecasted average rate base for 2001 of $526,065,000. The application was approved following a public hearing.

P.U. 30(2000-2001).

The automatic adjustment formula, established by the Board in 1998, was used to set rates for 2001. Based on the average of long-term Canada bond rates, the deemed rate of return on equity for 2001 was set at 9.25%. The resulting rate of return on rate base fell within the range that had been set for 2000. The rate of return on rate base became 10.13%, which fell within the range of 10.10% to 10.46% set for 2000. As a result, there was no change in rates arising from the operation of the formula.

P.U. 37(2000-2001)

On February 8, 2001, Newfoundland Power Inc. applied for permission to dispose of $7,743,000 excess revenue resulting from the favorable settlement of an outstanding issue with Canada Customs and Revenue. These excess earnings caused the company's rate of return on rate base for 2000 to exceed the upper limit of the allowed rate of return (10.46%). The company proposed to dispose of the amount through a one-time credit of 1.90% of customers' total billing amounts during the period January 2000 to December 2000. The application was approved following a public hearing and customer rebates were issued on April billings.

Order Pending

On May 8, 2001, Newfoundland Power Inc. applied to the Board for permission to amend its 2001 Capital Budget to include the purchase of the support structures of Aliant Telecom Inc. located in the applicant's service territory. This required approval of additional capital expenditures of $45,858,000 over a five-year period, with 50% of this amount ($26,245,000) payable in 2001. The structures being purchased include 69,848 joint use poles and 32,027 non-joint use poles. The decision of the Board on this application is pending.

CIAC Review

The Board is responsible for the Contribution in Aid of Construction charges of Newfoundland Power Inc. and Newfoundland Hydro as they relate to the provision of line extensions on behalf of commercial and residential customers. The current CIAC Policy approved for use by the Board requires prior approval of all line extensions for seasonal, residential customers, as well as for any line extensions where the construction costs are estimated to exceed $25,000.

During the preceding fiscal year, the Board dealt with eighteen CIAC applications.

Automobile Insurance

The Board continues to exercise responsibility for the regulation of automobile insurance rates charged by companies operating in the province. During the 1997 year, the property and casualty industry was subjected to a review by a Select Committee of representatives of the House of Assembly. In March 1998, this Committee reported to the House with recommendations regarding changes to the regulation of the automobile insurance industry as it relates to rates and the Board's continued involvement therewith. At the time of this report, the Board is aware of limited progress towards implementation of the Select Committee's Report.

During the past year, the Board completed a hearing to review the rates charged by the non-profit residual automobile-insurance market known as Facility Association. The main issue involved the reporting of excess profits by the Association and whether profits were generated by rates approved by the Board. The Board found that Facility Association acted merely as an administrator of the pool of funds representing the insurance premiums paid and that, while profits may have been generated by these funds and regardless of to whom the profits belong, they should not be used in setting future rates. The Board also found that while the rates approved contributed to the profits, those rates were approved on the basis of sound actuarial principles and the best available information at the time.

During the preceding twelve months, the Board has issued 73 orders on insurance matters.

Other Noteworthy Events

In January 2001, David Vardy announced his retirement from public service. Dave was appointed Chair and CEO of the Board in September 1994. Prior to his appointment, Dave had a long and distinguished career in the provincial civil service holding a number of senior positions. In 2000, Dave received the Gold Medal Award of the Professional Institute of the Public Service of Canada.

The Board's current chair is Robert (Bob) Noseworthy. Bob was appointed Chair/CEO in January, 2001. He is a graduate of Memorial University of Newfoundland and holds an Engineering Degree from Nova Scotia Technical College (now Dal Tech) as well as a Master of Business Administration from the University of Western Ontario. His most recent responsibilities included Deputy Minister of the Department of Municipal and Provincial Affairs, Chairman/CEO of the Newfoundland and Labrador Housing Corporation and Chair of the Municipal Assessment Agency.

National Energy Board

Several events that took place in the 2000-2001 period highlight the broad mandate of the National Energy Board (the Board or NEB). The Board aspires to be a respected leader in safety, environmental protection and economic regulation, which is reflected in the four overriding end state goals that the Board has set. The following summary presents some of the most significant events and emerging issues facing the Board, in the context of these goals.

Goal 1: NEB-regulated facilities are safe and perceived to be safe

Goal 2: NEB-regulated facilities are built and operated in a manner that protects the environment and respects individuals' rights

A primary aspect of the NEB's purpose is to promote safety and environmental protection. This is reflected in the above two corporate goals. While these two goals have separate intents, they are operationally linked and form the cornerstones of the NEB's physical regulation program.

The inherent risks from facilities under the NEB's jurisdiction are effectively managed through competent design, construction, operation and maintenance practices. While the primary responsibility for safety and environmental protection rests with industry, the NEB plays a significant role in promoting these aspects by ensuring that a regulatory framework is in place that encourages companies to maintain or improve their performance.

In order to meet its safety and environmental goal, the NEB has put significant effort into the development of its own environmental and safety management program. An integral part of the Board's safety and environmental program consists of conducting management system audits, in line with the Onshore Pipeline Regulations, 1999 (OPR). In mid-2000, the NEB undertook pilot audits to develop and apply appropriate audit procedures and protocols using the goal-oriented regulations, as intended in the OPR. In October 2000, the NEB began conducting OPR management system audits on four companies, with a focus on the companies' emergency response, continuing education and pipeline integrity programs. Over the next year, the NEB intends to expand the scope of future audits to include additional program elements set out in the OPR.

Part of the NEB's Safety Management Program is the development of Safety Performance Indicators, which will assist in evaluating the effectiveness of safety programs of NEB-regulated companies. The total number of incidents and ruptures on NEB-regulated pipelines are two indicators the Board has been tracking for several years. In 2000, 47 incidents were reported and there was one rupture on the Westcoast Energy Inc.'s (Westcoast) mainline east of Hope, BC. These numbers continue a six-year declining trend. While the trend is positive, it does not reduce the significance of particular events. A notable incident, which resulted in serious injury to an employee, was the explosion of a compressor station control building owned by Gazoduc TQM at East Hereford, Québec. Both the NEB and the Transportation Safety Board are investigating the incident to determine the cause of the explosion.

The Board also takes steps to be proactive in preventing incidents from recurring. Following a number of fires on Westcoast's Pine River Gas Plant Sulphur Pipeline, the Board issued an order directing Westcoast to stop all work on the pipeline. The Board later held a hearing on this matter and decided in April 2001 that it would not allow Westcoast to reopen the pipeline until certain safety issues were addressed.

Goal 3: Canadians derive the benefits of economic efficiency

The Board strives to achieve this goal in three ways: through the Decisions it renders; through the energy market information it produces; and by ensuring regulatory efficiency.

Providing and interpreting energy market information contributes to the more efficient operation of energy markets. In the last year, as part of its energy monitoring, the Board issued five Energy Market Assessments (EMA), which are reports providing analyses of the major energy commodities. The Board also initiated the production of a comprehensive all energy long-term outlook on Canadian energy issues and trends. The next Canadian Energy Supply and Demand report is expected to be completed in 2003.

Two of the EMAs are on natural gas. Canadian Natural Gas Market Dynamics and Pricing, which describes the price responses to changing supply and demand conditions in the natural gas market, was released in November 2000. The report concluded that the natural gas market has been functioning so that Canadian requirements for natural gas have been satisfied at fair market prices. Short-Term Natural Gas Deliverability from the Western Canada Sedimentary Basin 2000-2002, which examined the factors that affect natural gas supply over the short term and presented an outlook for deliverability, was released in December 2000.

In October 2000, the Board released an EMA entitled Canada's Oil Sands: A Supply and Market Outlook to 2015. The report examined the supply and market for bitumen and synthetic crude oil, the history of oil sands development, and the impact of the development on energy markets in Canada. In May 2001, the Board issued an EMA entitled North American Natural Gas Liquids Pricing and Convergence, which provides background on NGL pricing and the impact of energy price convergence.

In May 2001, the Board released its first EMA on the electricity market: Canadian Electricity Trends and Issues. The report examined electricity demand and generation in Canada and provided a province-by-province analysis of trade, regulatory developments and electricity prices.

The restructuring and deregulation of the electricity market taking place throughout North America is having an impact on the type of applications received by the Board, as it is encouraging further regional integration of the electricity and natural gas sectors. This is exemplified by three applications currently in front of the Board: one from Sumas Energy 2, Inc. for an international power line from the United States to a point near Abbotsford, British Columbia; one from New Brunswick Power for an international power line from the US border near Woodland, Maine to the Point Lepreau Peninsula; and one from Georgia Strait Crossing Pipeline Limited for a natural gas pipeline from Sumas, Washington to Vancouver Island.

The Board held a number of hearings on various projects that contributed to the ongoing development of an efficient pipeline transportation network. These hearings were with respect to new gas pipelines in Northeastern British Columbia (Ricks Nova Scotia Co.'s Ladyfern Pipeline Project and Murphy Oil Company Ltd.'s Chinchaga Sales Gas Pipeline Loop) and in Southeastern Alberta (AEC Suffield Gas Pipeline Inc.'s North Suffield Pipeline), expansion to an existing oil pipeline in Saskatchewan and Alberta (Enbridge Pipelines Inc.'s Terrace Expansion Program Phase II) and suspension of service on a petroleum product pipeline in Ontario (Trans-Northern Pipelines Inc.'s Don Valley Lateral).

The Board approved tolls for Maritimes and Northeast Pipeline Management Ltd. (M&NP) in August 2000. A new application for tolls for 2001 has been received and will be dealt with in a hearing commencing October 11, 2001. TransCanada Pipelines Ltd. (TransCanada) filed an application in May 2001 regarding its 2001 and 2002 tolls and tariff. The Board was also served with an application regarding TransCanada's cost of capital in June 2001. The Board last specifically addressed cost of capital matters in the RH-2-94 multi-pipeline cost of capital decision, issued in March 1995. The Board has taken several steps to ensure it will be in a position to address this matter efficiently, such as the organization of a cost of capital seminar for staff in November 2000.

As part of its ongoing efforts to increase regulatory efficiency, the NEB continues to prepare for an anticipated Northern pipeline application and has established a Northern Preparedness Steering Committee in May 2000. This work relates to the NEB Act and the Canada Oil and Gas Operations Act (COGO Act) and includes consultations with other regulators to clarify and streamline the regulatory process for pipeline associated facilities. In late 2000, the NEB and the Mackenzie Valley Environmental Impact Review Board signed a Memorandum of Understanding to establish a cooperative framework for environmental impact assessment in the Mackenzie Valley. The NEB is also actively engaged in defining future regulatory needs and processes with other federal departments and regulators in the Northwest Territories and the Yukon.

Goal 4: The NEB meets the evolving needs of the public to engage in NEB matters

In the pursuit of Goal 4, the NEB has established a Public Engagement Program. In March 2001, The Board held an internal workshop on public engagement in decision making with a purpose to begin to develop a shared vision of public engagement at the Board. With the intention to build relationships with stakeholders, Board Members travelled to Québec and Atlantic Canada to meet with government agencies, regulators and interest groups. Delegations of Board Members and staff also visited various stakeholders in the Yukon, the Northwest Territories and Alaska to discuss the opportunities and challenges associated with development activity in the North.

The Board also held public consultation meetings to discuss the environmental assessment and regulatory review processes with respect to specific projects, with the intent of making its processes more understandable to the people who would like to participate in them.

The NEB realizes that, in order to effectively participate in Board matters, Canadians need access to easy-to-understand, timely and targeted information. The NEB's Web site contains, among other things, information on the Board's regulatory role, energy markets assessment reports, statistical information, Hearing Orders, Reasons for Decisions and hearing transcripts. In December 2000, the Board broadcasted a hearing using audio stream through its Internet site and plans to improve access to hearings through the continued use of audio stream. The Board also recognizes the need for personal interaction; it received nearly 3000 calls in 2000 on its toll free number at 1-800-899-1265.

In order to provide easy access to the Board's regulatory filings, the Board's Electronic Filing System (ERF) was officially initiated on 1 April 2001. Two weeks later the Board received its first ERF-compliant application. ERF can be accessed through the Board's Web site (www.neb-one.gc.ca) and provides a method for creating, storing, exchanging, searching and referencing regulatory filing information.