
ENERGY (ELECTRICITY) CORPORATE

Prepared by:

Lou Cusano

Tel: (403) 266-9097 • Fax: (403) 266-9034
E-mail: lcusano@stikeman.com

David Wood

Tel: (403) 266-9068 • Fax: (403) 266-9034
E-mail: dwood@stikeman.com

&

Glenn Zacher

Tel: (416) 869-5688 • Fax: (416) 947-0866
E-mail: gzacher@stikeman.com

Stikeman Elliott LLP

5300 Commerce Crt W, 199 Bay St
Toronto, ON M5L 1B9
www.stikeman.com

OVERVIEW

Electricity restructuring in Canada remains limited to only a few provincial jurisdictions. In those jurisdictions that have introduced private sector reforms, the results have been mixed and the process has been slow.

Alberta's electricity market is the most evolved, and it has stimulated the most private sector investment. No significant regulatory changes have interrupted the evolution of Alberta's market over the past year.

Ontario sought to introduce both wholesale and retail competition in 2002. High prices and other circumstances, however, conspired to bring a quick end to the market. Ontario has since adopted a "hybrid market." The most significant recent regulatory development in Ontario has been the Ontario Power Authority's ("OPA") release of its Supply Mix Advice Report and the provincial government's ensuing Supply Mix Directive. This was the first major step toward the OPA's development of a 20-year Integrated Power System Plan which the OPA aims to file with the Ontario Energy Board ("OEB") in mid to late 2007 and have approved by the OEB the following year.

Some limited progress toward restructuring was made in British Columbia with the creation of the British Columbia Transmission Corp. ("BCTC"), whose mandate is to manage and provide non-discriminatory access to BC Hydro's transmission system. As well, in March 2007, the British Columbia Utilities Commission approved BC Hydro's Integrated Electricity Plan and Long-Term Acquisition Plan.

At the federal level, the last year has seen further progress toward the adoption of North American mandatory reliability standards. There have also been developments concerning the construction of international transmission projects.

NATIONAL NORTH AMERICAN RELIABILITY STANDARDS

Over the past year greater clarification has emerged as to how a North American Electricity Reliability Organization ("ERO") will operate. Investigations into the August 2003

blackout resulted in a joint Canada-US recommendation to subject all transmission owners, operators and users to mandatory reliability standards. The 2005 *US Energy Policy Act* required the Federal Energy Regulatory Commission ("FERC") to certify and approve an ERO for the US. In July 2006, FERC approved the North American Reliability Council ("NERC") as the ERO in the US. NERC will be responsible for the development and enforcement of reliability standards.

As a result of discussions held by a Canadian-American governmental working group, it was decided to have NERC file for recognition with Canadian provincial and federal regulators as the mandatory standards authority for Canada. NERC has now made such filings with energy regulators in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick and Nova Scotia, as well as with the National Energy Board ("NEB"). The NEB has recognized NERC as the ERO for North America and memoranda of understanding have been negotiated with other regulators under which NERC reliability standards will be made mandatory and enforceable, and provincial agencies will ensure compliance with NERC standards.

FEDERAL ELECTRICITY FACILITIES APPROVALS

In the past year the Federal Court of Appeal confirmed the NEB's broad interpretation of the environmental factors that it can take into account in considering applications to construct international power lines. The developer of a power generation plant in Washington State had applied to the NEB for leave to construct an international power line that would link its plant to the BC power grid through which the plant would export its energy to the United States. Residents in the BC Fraser River Valley opposed construction of the power line, arguing that the operation of the proposed power plant would impose a significant burden on the Fraser Valley airshed. The developer of the plant and power line, Sumas Energy 2, Inc., argued that in considering its application, the NEB could only take into account the environmental impact that the line might cause and could not consider the potential environmental effects in Canada of the power plant.

The NEB disagreed, holding that the broad language of its statute permitting it to take into account "all the factors it considers relevant" in determining whether a facility is required by the "present and future public convenience and necessity" entitled it to consider the power plant's environmental impact. The Federal Court of Appeal upheld this decision, finding that the choice of relevant factors was for the NEB alone and the court would give the Board considerable deference in its choice of factors. The long-term implications of this decision for electricity facilities application remains to be seen.

ONTARIO

Integrated Planning

The OPA is responsible for developing a 20-year Integrated Power System Plan ("IPSP") and submitting it to the OEB for approval.

The OPA took the first step in preparing its plan when in December 2005 it submitted to the Minister of Energy its Supply Mix Advice Report. In June 2006, the Minister responded by issuing its Supply Mix Directive to the OPA in which the Minister significantly increased the long-term target for the amount of demand reduction achieved by conservation to a total of 4,950 MW by 2025. The Minister agreed with the

OPA's advice on the use of renewable energy such as hydro-electric, wind, solar, and biomass for electricity generation, setting a 2010 target of new renewable generation of 2,700 MW and a 2025 total capacity of 15,700 MW. The Directive adopted the OPA's "smart gas" recommendation, specifying that natural gas generation should be used to meet peak demand and reflect a high-efficiency, high-value use of the fuel. The Minister confirmed that plants for coal-fired generation in Ontario are to be replaced by cleaner sources "in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario."

The Directive also provided some clarification on the future of nuclear power in Ontario. The Minister directed that the IPSP plan for nuclear capacity to meet base-load electricity requirements, but limited the installed in-service capacity of nuclear power over the life of the plan to 14,000 MW. Directions were also given to plan for additions to the transmission system to facilitate the development of renewable energy resources such as wind and hydroelectric power in Ontario's north.

The OPA has been engaged in extensive stakeholder consultations on the IPSP and has issued eight discussion papers on various topics related to the IPSP over the past year. The OPA also recently established communication with First Nations and Métis leaders to ensure that the interests of these communities are actively considered in the IPSP process. The OPA currently expects to file the IPSP with the OEB in latter part of 2007 and to proceed with a hearing before the OEB beginning in early 2008.

Supply

In February 2007, the OPA issued a progress report on electricity supply in Ontario. The report highlights that, as of January 2007, the OPA was managing 39 contracts for 8,337 MW of electricity supply capacity. In 2006 the OPA issued RFPs for generation in the western Greater Toronto Area, which resulted in a contract with TransCanada Energy Limited for a generating station with a contract capacity of 600 MW to be built along the Highway 401-407 corridor. In cooperation with the OEB, the OPA has also developed a Standard Offer Program for small renewable-generation projects where developers can enter into a standard-form agreement to provide power at fixed prices for different resources.

Transmissions Facilities

On March 29, 2007, Hydro One Networks Inc. filed an application with the OEB for leave to construct approximately 180 kilometres of double-circuit 500 kV electricity transmission line adjacent to the existing transmission corridor extending from the Bruce Power Facility in to Hydro One's Milton Switching Station.

Electricity/Natural Gas Interface

When gas-fired generation emerged as the favoured resource to meet Ontario's incremental demand in the medium term and enable the retirement of some coal facilities, the OEB initiated the Natural Gas Electricity Interface Review ("NGEIR") in an effort to design new gas-transportation services to serve the operating needs of dispatchable gas-fired generators. After reaching a settlement to allow enhanced transportation services for both Union Gas Ltd. and Enbridge Gas Distribution Inc., the parties in the NGEIR proceeding asked the OEB to determine whether regulatory oversight was necessary to set prices and approve contracts with the two utilities for gas storage. In a

decision issued in November 2006, the OEB concluded that the storage market in Ontario is workably competitive and decided to forbear from regulating contracts between the utilities and customers located outside the utilities' franchise area. The OEB expects that competition will stimulate the development of new innovative services required by gas-fired generators.

Day-Ahead Electricity Markets

The Independent Electricity System Operator ("IESO"), which is the entity responsible for directing the operation of the Ontario power grid, remains committed to developing a day-ahead market for Ontario, particularly in view of the fact that day-ahead markets characterize several of the neighbouring control areas with whom the IESO schedules imports and exports of power. After an unsuccessful attempt to implement a day-ahead market in 2004, the IESO has developed and implemented the Day Ahead Commitment Process ("DACP") over the past two years. While DACP is not a true day-ahead market, the initiative has enhanced system reliability by increasing the probability that generation units will be available for dispatch when required in the real-time market. In its most recent business plan, the IESO allocated \$16 million over two years to designing a full day-ahead market for Ontario. This allocation was approved by the OEB in the IESO's 2007 rate application.

Smart Meters

As part of its conservation strategy, the provincial government has established targets for the installation of 800,00 smart meters by December 31, 2007, and installation of smart meters for all Ontario customers by December 31, 2010. Smart meters record hourly data for every customer and transfer that data to the distributor and a centralized database. The data is then made available to customers and other interested parties. The aim of the initiative is to provide customers with the incentive and the ability to control their energy costs by moving usage to off-peak periods and reducing energy use during peak periods. The government has the power to create or designate a "Smart Metering Entity" to administer and deliver any part of the initiative and to engage in competitive procurement activities. To date, the government has not created or designated a "Smart Metering Entity", but has entered an agreement with the IESO under which the IESO is responsible for the implementation of the initiative. The IESO expects the initiative to go-live with the first batch of participating distributors in the summer of 2007.

ALBERTA

Regulated Rate Option Regulation

Owners of electric distribution systems in Alberta are required to offer a regulated rate product to certain small-consumption "eligible customers" who have not selected a competitive electricity retailer, or to appoint a regulated rate provider. The regulated rate product, offered under the terms of a tariff that must be approved by the relevant regulatory authority, is similar to standard-offer service in other unbundled jurisdictions.

Under a new regulation, the relevant provisions of which came into effect on July 1, 2006, the structure of the regulated rate product has been significantly altered. The new regulation prescribes a rate structure that is based on both long- and short-term market prices, with a rate that is set monthly. For the next five years, the regulated rate structure will change each year on July 1. For the period from July 1, 2006, to June 30, 2007, at least 20 per cent of the monthly volumes must

reflect monthly forward market electricity prices. Each year, the minimum percentage that must be based on monthly forward market electricity prices increases by 20 per cent until June 30, 2010, at which point the regulated rate will be based 100 per cent on monthly forward market electricity prices.

Changing Roles

On November 28, 2005, the Department of Energy ("DOE") issued a policy paper for stakeholder comment. Entitled *Role and Mandate Refinements for Alberta Electric Industry Implementing Agencies*, the paper outlined a proposal to modify the roles of the Alberta Energy and Utilities Board ("EUB"), the market surveillance administrator ("MSA") and the independent system operator ("ISO"). Generally speaking, the proposed shift would see the ISO assuming greater responsibility for certain matters that are now within the jurisdiction of the EUB, and would give the MSA additional powers.

The ISO is the not-for-profit independent system operator for the Alberta transmission system, established under the *Electric Utilities Act*. In addition to responsibility for transmission planning and operation, the ISO is also responsible for the operation of the Alberta Power Pool. Also established under the *Electric Utilities Act*, the MSA has a broad mandate to conduct surveillance of and investigations into the structure and performance of the Alberta electricity market, and the conduct of market participants (both regulated and unregulated).

Among other things, the November 28, 2005 paper proposed that the ISO be able to approve its own costs (the ISO's "own costs" tariff is currently approved by the EUB), and would eliminate the need to have the EUB approve the need for certain smaller transmission projects.

Stakeholder reaction to the November 28, 2005, paper was mixed, and on April 28, 2006, the DOE issued a paper entitled *Response to Stakeholder Comments and Recommendations on the November 28, 2005, Paper*. Responding to stakeholder concerns, the DOE has indicated that the EUB should not be completely eliminated from the determination and approval of the ISO's own costs. As a result, on April 30, 2007 the *Transmission Regulation* was amended to the effect that once the ISO board has approved the ISO's own administrative costs the EUB must consider them to be prudent unless an interested person establishes that those costs are instead unreasonable.

The amended *Transmission Regulation* also contains substantive amendments relating to the ISO having stakeholder consultation obligations; making rules relating to an abbreviated needs identification approval process; making rules relating to generating unit emergency operating requirements; and making rules with respect to monitoring compliance and enforcement of reliability standards.

Wind Power

Alberta currently has approximately 300 MW of wind power connected to the transmission system, and there are additional projects in various stages of development. The ISO has recently completed a wind power variability study, and has concluded that above 900 MW (approximately 10 per cent of total generation capacity), the variable nature of wind power may be likely to pose control problems that could impact the reliability of the Alberta transmission system and

lead to violations of reliability and operating standards. The ISO has therefore indicated that it will not connect more than 900 MW of wind-powered generation to the Alberta transmission system until appropriate mitigation measures can be established to ensure that the additional wind power will not jeopardize system reliability. At the present rate of wind power development, the ISO has estimated that this 900 MW threshold could be reached by late 2007. The ISO has developed a Market and Operational Framework for Wind Integration in Alberta to facilitate stakeholder involvement in determining how to reliably integrate wind power into the Alberta transmission system.

BRITISH COLUMBIA

Integrated Planning

In March 2007, the British Columbia Utilities Commission ("BCUC") approved BC Hydro's Integrated Electricity Plan ("IEP") and Long-Term Acquisition Plan ("LTAP"). The IEP sets out a 20-year plan on how the utility could meet future electricity needs through a combination of demand-side management and resource acquisition, while the LTAP is a shorter-term action plan. In its decision, BCUC approved the following expenditures:

- \$1.7 million to undertake preliminary work on the next generation of BC Hydro's demand side management programs, including completion of an updated Conservation Potential Review;
- \$800,000 for the Greater Vancouver Water District micro-hydro load displacement project;
- \$2.9 million to undertake an "all source" competitive call for energy in 2007;
- \$500,000 on to conduct preliminary work for a further competitive call in 2009;
- \$12.5 million to complete the design work on a 480-MW expansion to its Revelstoke generation station; and
- \$3 million to complete the preliminary work for further expansions to its Revelstoke or Mica units.

Transmissions Facilities

In 2006, the BCTC was granted leave by the BCUC to construct a replacement and upgrade of some existing 138-kV transmission lines running from the mainland to Vancouver Island with 230-kV circuits. In reaching its decision, the BCUC determined that there would be an electrical energy capacity shortfall on the Island commencing in the winter of 2007/08 if the line was not constructed.

A number of residents of Tsawwassen and the Gulf Islands subsequently appealed the BCUC's decision to the BC Court of Appeal. The primary issue in the appeal was whether the BCUC had erred in not finding the "precautionary principle" to be a mandatory rule of construction when interpreting the relevant legislation. In a decision released on April 13, 2007, the Court refused the appellant's request to issue a declaration that the precautionary principle was a mandatory rule. Further, the Court concluded that other issues raised by the appellants were not properly before the Court and accordingly refused to grant the appeal.

Kitimat Smelter

On March 28, 2007, the BC Supreme Court dismissed a

petition by the District of Kitimat regarding the sale of power from Alcan's Kemano facilities. The District sought an order that Alcan's decision to restrict its production at the Kitimat smelter while selling power from Kemano into the market was contrary to the "regulatory scheme" agreed to between Alcan and the Province in 1950. The Court concluded that neither

the governing legislation nor the agreement between Alcan and the Province restricts Alcan in the decisions it chooses to make with respect to the sale of power generated at Kemano. The Court stated that Alcan is free to sell its Kemano power or use it for the Kitimat smelter as it considers appropriate.

Ideas. Solutions. Success...in Electricity.



Lou Cusano
(403) 266-9097
lcusano@stikeman.com



David Wood
(403) 266-9068
dwood@stikeman.com



Glenn Zacher
(416) 869-5688
gzacher@stikeman.com

STIKEMAN ELLIOTT

STIKEMAN ELLIOTT LLP | MONTRÉAL TORONTO OTTAWA CALGARY VANCOUVER NEW YORK LONDON SYDNEY

www.stikeman.com