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BARRISTERS AND SOLICITORS

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INTRODUCTION

Welcome to Lawson Lundell's energy law newsletter. This quarterly publication aims to keep readers informed about developments in the energy sector in Western Canada. It is written and edited by Lawson Lundell lawyers who practice in the energy sector. For information regarding this newsletter call Jeff Christian at 604.631.9115. For information about Lawson Lundell and its Energy Law Group, please contact Chris Sanderson at 604.631.9183, or visit our website at www.lawsonlundell.com.

With this edition of the newsletter we include a feature article called Northern Pipelines - Status Report. It summarizes the recent massive NEB filing regarding the proposed Mackenzie Valley gas pipeline project, as well as U.S. developments relating to the proposed Alaska Highway gas pipeline project.

NATIONAL

Supreme Court of Canada Affirms Paramountcy of Tariff

In *Hydro-Quebec v. Modestos Glykis*, 2004 SCC 60, the Supreme Court of Canada, by a 7-2 majority, overturned a Quebec Court of Appeal decision and restored a trial judgment in favour of Hydro-Quebec arising out of a service disconnection. At trial, Hydro-Quebec had successfully defended an action brought for damages by a customer who was disconnected pursuant to bylaws established by Hydro-Quebec that governed its terms and conditions of service (Hydro-Quebec being largely self-regulated). The customer argued that in considering whether Hydro-Quebec had the right to disconnect service at a premise other than the premise in respect of which a bill remained unpaid any ambiguity in the language of the bylaw provision ought to be construed in favour of the customer. In rejecting this argument, the Court noted that the relationship between the two was not contractual and free to be negotiated, but rather was determined as a matter of law. It followed, the Court reasoned, that the interpretation principles to be applied were those of statutory interpretation. The decision brings Canadian jurisprudence more in line with United States law on the question of proper principles to apply where interpreting a tariff. The "filed rate doctrine", as those principles are known in the United States, holds that a public utility's tariff defines the entirety of the legal relationship between the utility and its customers, notwithstanding any contractual or equitable principles that might otherwise apply.

BRITISH COLUMBIA

BC Hydro to Acquire Columbia Power Corporation and Columbia Basin Trust Generation Projects

In September BC Hydro announced that its Board approved in principle the acquisition by BC Hydro of the four generation projects jointly owned by the CBT Energy Inc. and the Columbia Power Corporation. Two of the four projects are currently in operation, being the Arrow Lakes project (185 MW) and the Brilliant project (145 MW); one of the projects – Brilliant Expansion - is under construction (120MW); and the fourth is the proposed Waneta Expansion (up to 435MW). All are located in south-eastern British Columbia in the Canadian portion of the Columbia River basin. The Columbia Power Corporation is a Crown corporation wholly owned by the British Columbia government, while CBT Energy Inc. is a wholly owned subsidiary of the Columbia Basin Trust, established pursuant to provincial legislation. Both organizations have a regional development component to their mandate. The entire output of the Arrow Lakes project is already committed under a long term power sale agreement to BC Hydro, as is 40% of the output of the Brilliant Expansion project, while the entire output of the Brilliant project is committed to Fortis BC. BC Hydro's Board will be considering a due diligence review in the next few months before committing to the transaction.

BCUC Denies PNG Application to Re-capitalize as an Income Trust

In a decision issued in late July, the BC Utilities Commission (BCUC) denied an application by Pacific Northern Gas (PNG) and its affiliates to re-organize and re-capitalize as an income trust. Under the proposal, the PNG affiliates would have amalgamated into a entity that would have owned and operated the current PNG assets, and would in turn have been owned by a new entity, the PNG Income Trust. Existing PNG shareholders would have become unitholders of the PNG Income Trust, and received cash distributions at low effective income tax rates. The BCUC stated in its decision that the proposal before it would have been the first such income trust created out of a traditionally regulated public utility. (The underlying assets of many if not most income trusts are regulated, if at all, on a complaints basis, and in particular are not subject to regular cost-of-service rate-making as PNG currently is).

In denying the application, the BCUC noted that insofar as the proposal would have required it to deem a capital structure for rate-making purposes far different from the actual underlying capital structure, and would have required including in the cost of service income taxes that would have been payable only under the current structure and not the proposed structure, it would be venturing into unprecedented regulatory areas. In light of these observations, the BCUC found on the evidence that the potential benefits to ratepayers were uncertain, that the risk of imposing costs on future PNG ratepayers was high, and that there was too much uncertainty regarding the justness and reasonableness of PNG's rates generally to approve the transaction.

BC Hydro Revenue Requirement Decision

On October 29, 2004, the BCUC issued its decision on BC Hydro's F2005 and F2006 revenue requirement application. BC Hydro had applied for an 8.9% across the board rate increase for F2005; no increase for F2006 rates; the approval of certain deferral accounts; the approval of its capital and resource acquisition plan; and a reduction in certain wholesale transmission rates. An across the board 7.23% rate increase had already been allowed on an interim basis. In its decision the BCUC largely approved the applications, with some revenue requirement adjustments. The final allowed rate increase, consequent upon the BCUC-directed adjustments, is to be filed by November 15.

One of the revenue requirement adjustments arises from the BCUC's treatment of the recent changes to accounting rules relating to the retirement of capital assets. Under recent changes to GAAP, previously recorded provisions for Future Removal and Site Restoration (FRSRs) are to be reversed unless they fall within the new, narrow definition of an Asset Retirement Obligation. The reversal of previously recorded FRSR charges is reflected in transfers to retained earnings and accumulated depreciation. In its decision, the BCUC accepted intervenor arguments that it would be appropriate to require BC Hydro to maintain the FRSR balance to be utilized for actual future dismantling costs, and ordered a vanance from the GAAP rule.

In the course of considering BC Hydro's capital and resource acquisition plans the BCUC also made a number of significant determinations regarding the interplay between BC Hydro's planning processes and anticipated regulatory processes. Most significantly, the BCUC accepted that BC Hydro's current 20 year Integrated Electricity Plan (IEP) is a planning document useful for resource evaluation in the short to medium term but is not itself amenable to BCUC review or approval. Instead the BCUC will review BC Hydro's annual 4 year capital and resource expenditure plans (known as the REAP) and, in a parallel process, conduct a Resource Option Review designed to identify the available resource options, including expected energy capacity and per unit cost ranges, for later inclusion in the IEP.

ALBERTA

AESO Application to Reinforce Southwest Alberta Transmission System Referred Back

On September 7, 2004, the Alberta Energy and Utilities Board (AEUB) issued Decision 2004-075 in which it decided to refer back to the Alberta Electric System Operator (AESO) its April 5, 2004 needs identification application for 240 kV transmission system development in southwestern Alberta. Seeking more information from the AESO, the AEUB ordered the AESO to more fully assess and describe existing constraints on the southwest transmission system through the completion of a Congestion Analysis, and to evaluate viable transmission upgrade alternatives available to address the existing constraint. The Board indicated that it expects the AESO to specifically consider the provisions of the newly enacted Transmission Regulation that came into force after the conclusion of the hearing, including the new planning design criteria that mandates 95% of expected economic wholesale transaction to be realized without transmission congestion. As the additional analysis requested is significant, it is not expected that the matter will be finally determined until early 2005.

The Pincher Creek – Lethbridge area in southwestern Alberta has the highest wind energy potential in the province. Over 220 MW of generating capacity has been installed to date, and a further 600 MW of new wind generation is expected to develop in the area by the end of 2005. The proposed development consists of the construction and operation of new 240 kV transmission lines between existing substations, as well as numerous alterations and upgrades to associated facilities.

Recovery of Management Fees Requires Added Value: Alberta Court of Appeal

The Alberta Court of Appeal has recently confirmed that there should be no increase in rates in the form of management fees unless value over and above the actual costs of the services is provided to customers. In 2000 and 2001, Atco Electric Ltd. (ATCO) submitted regulated rate option tariffs (RROT) for approval by the AEUB. Each application included management fees intended to compensate ATCO for providing the regulated rate option. In both cases, the AEUB refused to allow ATCO to recover the proposed management fee in the RROT, holding that the RRO service was similar to other services that ATCO is able to provide for a regulated return on rate base using its utility assets and staff, and therefore did not constitute added value to customers. ATCO appealed both decisions to the Alberta Court of Appeal. The Court granted leave to appeal both decisions, and heard the appeals together earlier this summer. On August 16, 2004, the Alberta Court of Appeal dismissed both ATCO appeals, confirming that the Board was not wrong when it refused to include the management fees as proposed in ATCO's rates. The Court determined that the Board acted properly when it established principles to be used to evaluate the non-energy component of the RROT, and did not act unreasonably when it concluded that ATCO would be sufficiently compensated through its distribution tariff. Noting that the AEUB did not in principle rule out the awarding of a management fee, and that it left open the possibility that in some circumstances avoided costs may be treated as a value-added service and be paid through a management fee, the Court concluded that the Board was free to establish "value added" criteria for approval of a management fee, having observed legislative requirements.

Calpine Obtains Leave to Appeal AEUB Deferral Account Decision

The Alberta Court of Appeal recently granted Calpine Canada Power Ltd. (Calpine) leave to appeal AEUB Decision 2003-099 in which the AEUB determined, among other things, that certain Rider C amounts should be considered refundable on an interim basis for the purposes of the 2002 deferral account reconciliation. Calpine sought leave to appeal the AEUB's decision on the basis that the AEUB was wrong when it concluded that amounts transmission customers had received or been charged under the Rider C mechanism in 2003 relating to deferral account balances as at the end of 2002 should be viewed as refundable on an interim basis. Calpine also challenged the AEUB's decision to allow the AESO to make retrospective adjustments to the Rider C fund in the reconciliation process for 2002, arguing that the 2002 Negotiated Settlement addressing deferral accounts was the exclusive means by which deferral accounts could be reconciled. On August 25, 2004, the Alberta Court of Appeal granted Calpine leave to appeal the decision, concluding that the AEUB may have been wrong when it effectively varied the STS rate set in its previous decision from variable to fixed, and classified its previous tariff approval as refundable on an interim basis. Whether prospective rate determination and retrospective adjustment methodology are distinctive processes having regard to accepted Negotiated Settlement language; whether prospective deferral account rates set in accordance with Rider C are final or interim in nature, and the AEUB's role in reconciling deferral accounts were important issues noted by the Court and that warranted review.

NUNAVUT

Qulliq Energy Corporation Files First-Ever Rate Application

On September 28, 2004, Qulliq Energy Corporation (Qulliq) filed a general rate application for review by the Utility Rates Review Council, its first in the seven years since it has been independent of the Northwest Territories Power Corporation. Qulliq is the umbrella company responsible for both electricity and petroleum products in Nunavut through two major subsidiaries: Nunavut Power Corporation and Qulliq Fuel Corporation. This application states that the rate increase is required due to rising operating costs. The application also seeks approval of a significant change to the governing rate setting principles in Qulliq's service territory. At present, consumers are charged on a community based rate structure where the cost to consumers reflects the cost of production in that particular community. Qulliq is applying to change the rate structure to a uniform territorial rate that would result in consumers throughout the territory paying the same rate based on Qulliq's average cost of operations and capital costs. If accepted, the proposed territorial structure will result in a rate increase in some communities and a rate decrease in others. If approved, the rate change is expected to come into effect by April 2005.

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Feature Article:
Northern Pipelines - Status Report

Mackenzie Gas Project

After 30 years of discussion, review, and half starts, the development of the Mackenzie River delta gas fields took a leap forward in recent months with a project filing at the National Energy Board (NEB).

On October 7, 2004, the following applications were filed by the proponents of the Mackenzie Gas Project—Imperial Oil Resources Ventures Limited (Imperial), the Mackenzie Valley Aboriginal Pipeline Limited Partnership (APG), ConocoPhillips Canada (North) Limited (ConocoPhillips), Shell Canada Limited (Shell) and ExxonMobile Canada Properties (Exxon):

- Development Plan Applications for three anchor onshore natural gas fields in the Mackenzie Delta—Taglu (operated by Imperial), Parsons Lake (operated by ConocoPhillips), Niglintgak, to be operated by Shell) – under the *Natural Energy Board Act*;
- an application for construction of the Mackenzie Gathering System under the *Canada Oil and Gas Operations Act;* and
- an application for a Certificate of Public Convenience and Necessity for a Mackenzie Valley gas pipeline under the *National Energy Board Act*.

These applications are supported by an Environmental Impact Statement (EIS), which assesses the potential socio-economic and environmental impact of all components of the proposed development.

The three anchor fields, Niglintgak, Taglu and Parsons Lake, are estimated to contain 165 Gm^3 (six trillion cubic feet) of natural gas.

The gathering system would collect natural gas and associated natural gas liquids (NGLs) from the three fields and transport them to a facility in the Inuvik area. It is expected to include:

- gathering pipelines, consisting of four sections, ranging in size from NPS 16 to NPS 30, totalling about 175 km of pipe;
- the Inuvik area facility, built to separate the gas and NGLs, and to compress, pump and cool the gas and NGLs. The facility would be located about 20 km east of Inuvik.
- a buried, NPS 10 NGL pipeline, about 475 km long, built from the Inuvik area facility to Norman Wells. The NGL pipeline would be built in the same right-of-way as the Mackenzie Valley pipeline. At Norman Wells, it will connect to the existing Enbridge pipeline.

The Mackenzie Valley Pipeline facilities include about 1,220 kilometres of NPS 30 pipe, a meter station at the Inuvik area facility, four intermediate compressor stations, a heater station and a pig receiver. The pipeline would extend from Inuvik along the east side of the Mackenzie River valley to Alberta where it would connect with an extension of the NOVA Gas Transmission Ltd.'s system just south of the Northwest Territories – Alberta boundary. The pipeline would have an initial design capacity of about 34 Mm^3 (1.2 Bcf) of natural gas per day. The pipeline could be expanded to an annual average capacity of about 55 Mm^3/d (1.9 Bcf/d) by adding compressor stations. The anchor field owners have contracted in aggregate for capacity of 23.5 Mm^3/d (0.83 Bcf/d). Currently, the remaining 10.5 Mm^3/d (0.37 Bcf/d) of capacity is uncommitted and is available for contracting.

The proponents have also applied for approval of the tolling principles to be applied to the Mackenzie Valley Pipeline. Under their proposal, the pipeline would provide firm service for a term of either 15 or 20 years. Authorized overrun service would also available to all firm service shippers. In addition, interruptible transportation service would be available to a shipper that has a firm Service Transportation Agreement, subject to the operating conditions of the pipeline. A short-haul toll for receipts south of the Little Chicago compressor stations would be offered. A rebate of 50% of the 20-year toll would be provided to shippers delivering gas to communities in the Northwest Territories along the pipeline route.

The total estimated cost of the five Mackenzie Gas Project components is about $7.7 billion. This cost includes future expenditures of about $0.7 billion at the anchor fields. The estimated costs for the construction phase, from mid-2006 to mid-2010, is about $6.2 billion, including the anchor fields, gathering system and gas pipeline.

The pipeline alone has an estimated capital cost of approximately $4.5 billion (2003 $Cdn.). Each owner of the pipeline would be responsible for providing the capital necessary to fund its proportionate share of construction costs. Imperial, ConocoPhillips, ExxonMobile and Shell intend to use internally generated funds to meet their capital requirements. The APG intends to establish conventional limited recourse project debt and equity financing for its share of the construction costs.

A decision to construct the project has not been made. The final decision to proceed with construction will depend on obtaining the necessary regulatory approvals and assessing any conditions attached to those approvals, as well as several other factors, such as natural gas markets, project costs and fiscal terms. Construction of the required facilities is expected to be completed in time to enable gas to be delivered to Alberta through the pipeline in 2009. Camp and equipment demobilization, construction clean-up and site reclamation will extend into the first year of operations in 2010. Construction planning is contingent on having approvals, permits and authorizations in time for construction to begin in summer 2006. These decisions will be subject to review as the regulatory process proceeds.

On August 18, 2004, the federal Minister of the Environment, the Chairperson of the Mackenzie Valley Environmental Review Board and the Chair of the Inuvialuit Game Council established a seven member Joint Review Panel to conduct the environmental impact assessment of the Mackenzie Gas Project. The findings of the Joint Review Panel are intended to form the basis of findings by the NEB and other permitting agencies on environmental matters. The NEB is expected to conduct hearings contemporaneously with the Joint Review Panel on other aspects of its mandate. Both the NEB and the Joint Review Panel will announce their hearing processes on the applications at a later date.

The Deh Cho First Nation has challenged the Joint Review Panel process. On September 2, 2004, the Deh Cho commenced a lawsuit in the Supreme Court of the Northwest Territories. On September 24, 2004, the Deh Cho commenced a second lawsuit in the Federal Court of Canada. Both lawsuits seek an injunction restraining the respondents from proceeding with the Joint Review Panel for the Mackenzie Gas Project under any Joint Review Panel Agreement that does not include the Deh Cho First Nation.

Alaska Pipeline Developments

Meanwhile, the proponents of a scheme to develop and transport natural gas from Alaska's North Slope, a project that has been on the books as long as the Mackenzie River project, have also made significant progress.

On October 11, 2004, the U.S. Congress approved a Military Construction Appropriations Bill that included loan guarantees for the construction of a US$20 billion pipeline to deliver natural gas from Alaska through Canada to the lower 48 states. The loan guaranty will make the government liable for 80% of the cost of the first US$18 billion of the project if it is not completed.

ConocoPhillips, Exxon Mobile Corp. and BP Plc, the three largest owners of Alaska's gas reserves, have stated that the Alaska Pipeline cannot be built without government incentives. The measures passed also set up an expedited review process whereby the typical multiple environmental impact statements could be consolidated into a single statement prepared by FERC. Not later than 60 days after the EIS is completed, FERC must issue an order granting or denying any application for a Certificate of Public Convenience and Necessity.

The incentives for the pipeline were originally included in an Energy Bill that has been stalled in Congress for nearly 4 years. The military construction appropriations bill, however, did not include the controversial floor price for natural gas that had been part of the Energy Bill.

If built, the Alaska pipeline could supply 4.5 Bcf per day, approximately 10% of U.S. demand. Permitting and construction would take approximately 10 years and would tap into the estimated 35 trillion cubic feet of gas of Alaska's North Slope.