RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO OIL AND GAS LAWYERS

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Surveyed herein are the recent regulatory and legislative developments of significance to the oil and gas industry. This article canvasses decisions of the courts, bulletins from national and provincial regulatory bodies, and legislative initiatives to provide a comprehensive update for the oil and gas lawyer.

Cet article examine en grandes lignes les derniers développements réglementaires et législatifs importants dans le secteur pétrolier et gazier. Il traite des décisions des tribunaux, des bulletins des organismes nationaux et provinciaux de réglementation et des initiatives législatives pour donner une mise à jour générale à l'avocat qui travaille dans le secteur pétrolier et gazier.

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I. INTRODUCTION

In this article the authors review Canadian oil and gas regulatory, legislative, and policy developments occurring in or relating to the period between April 2005 and April 2006.[1] Regulatory developments include decisions by or appeals from the following administrative bodies: the National Energy Board; the Alberta Energy and Utilities Board; the British Columbia Utilities Commission; the Ontario Energy Board; the Canada-Newfoundland and Labrador Offshore Petroleum Board; and the Canada-Nova Scotia Offshore Petroleum

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[1] The review is not exhaustive. Emphasis in the scope of material reviewed has been towards developments in the Canadian federal government and western provinces.

Board. Legislative developments in those affected jurisdictions and other policy developments of those administrative bodies are also identified.

II. REGULATORY DECISIONS AND APPEALS

A. NATIONAL ENERGY BOARD

The National Energy Board (NEB) is a federal agency mandated by the *National Energy Board Act*[2] to grant authorizations for the federal import and export of oil, natural gas, and electricity; to certify the construction and operation of interprovincial and international pipelines and power lines; to oversee safety matters in respect of the subjects; and to review the Canadian supply of all major energy commodities and the domestic and export demand for Canadian energy. The more significant oil and gas related NEB decisions of the past year are described below in the order they occurred.[3]

1. RH-2-2004 — APPROVAL OF TRANSCANADA PIPELINES LIMITED 2004 MAINLINE TOLLS AND TARIFF APPLICATION[4]

The NEB considered the cost of capital aspects of TransCanada PipeLines Limited's (TCPL) 2004 Tolls Application during Phase II of the RH-2-2004 public hearing held in Calgary, Alberta between 29 November 2004 and 4 February 2005. All other aspects of the 2004 Tolls Application had been heard during Phase I of the public hearing and the NEB rendered its decision on that phase of the hearing in September 2004.[5]

a. NEB's Decision of CAPP's Application for Review of Phase I of RH-2-2004

On 12 November 2004, the Canadian Association of Petroleum Producers (CAPP) applied for a review of the NEB's RH-2-2004 Phase I Reasons for Decision with respect to TCPL's 2004 Mainline Tolls. CAPP stated that the NEB committed the following errors that raised doubt as to the correctness of its decision:

(a) approving tolls for Non-Renewable Firm Transportation Service (FT-NR) to be determined on a biddable basis;

(b) allowing TCPL to include all forecasted long-term incentive compensation costs in its 2004 cost of service; and

2 R.S.C. 1985, c. N-7 [*NEB Act*].
3 NEB decisions can be obtained from the NEB's website, online: <www.neb-one.gc.ca>.
4 NEB, *In the Matter of TransCanada PipeLines Limited, 2004 Mainline Tolls and Tariff Application — Phase II*, Reasons for Decision RH-2-2004 (April 2005) [RH-2-2004].
5 In its Phase I Decision, 2004, the NEB decided, subject to any impact resulting from the Phase II Decision, to approve a net revenue requirement for 2004 of $1.7 billion and a rate base of $8.2 billion. This was compared to the 2003 net revenue requirement of $1.9 billion and a rate base of $8.6 billion. See NEB, *In the Matter of TransCanada PipeLines Limited, 2004 Mainline Tolls & Tariff Application — Phase I*, Reasons for Decision RH-2-2004 (September 2004).

(c) allowing TCPL to recover through tolls certain regulatory and legal costs relating to review and appeal proceedings.

On 18 May 2005, the NEB issued its decision.[6] In the first step of the NEB's review, it decided that,[7] with respect to the FT-NR issue, CAPP had raised a doubt as to the correctness of the decision on the basis that the NEB may have erred in approving a different toll for FT-NR than the cost-based toll charged for Firm Transportation (FT) with a step-down. With respect to the other two grounds of review, CAPP withdrew its ground of review, and the NEB found that CAPP had not raised a doubt as to the correctness of the Phase I decision with respect to regulatory costs.

The NEB proceeded to the second step of review on the FT-NR issue, to decide whether the NEB decision regarding the tolling of FT-NR should be confirmed, amended, or overturned. CAPP submitted that FT-NR would be traffic that flows under substantially similar circumstances and conditions to FT with a step-down. Both services could be used to market term-limited blocks of capacity. Further, a contract with no renewal provision (*i.e.*, FT-NR) is equivalent to a contract renewable at zero volumes (*i.e.*, FT with a step-down). Accordingly, in CAPP's submission, it was not open to the NEB to approve a different toll for FT-NR than the cost-based FT toll applicable to FT with a step-down.

The NEB agreed with CAPP's argument. It held that the RH-2-2004 Phase I Decision authorizing FT-NR to be tolled on a biddable basis should be overturned and found that the FT-NR service was to be tolled using the same methodology as for FT with a step-down. The original Panel should have had regard to the toll charged for the existing FT with a step-down service when setting the just and reasonable toll for FT-NR. The two services, FT with a step-down and FT-NR, constituted traffic of the same description transported under substantially similar circumstances and conditions. Accordingly, the original Panel erred by approving a toll methodology for FT-NR that could result in a different toll being charged for FT-NR than that in use for FT with a step-down.[8]

b. NEB's Decision — Phase II of RH-2-2004

Phase II of the RH-2-2004 proceeding considered the cost of capital aspects of the 2004 Tolls Application. TCPL's applied-for 2004 revenue requirement included an overall rate of return on a rate base of 8.93 percent, which incorporated the RH-2-94 Formula ROE[9] of 9.56 percent for 2004 on a deemed common equity ratio of 40 percent (an increase from 33 percent to be effective 1 January 2004) and an average cost of debt of 8.73 percent. TCPL submitted that the NEB was required to determine the cost of equity capital for the Mainline for 2004 using the comparable investment, capital attraction, and financial integrity standards that together comprise the fair return standard.

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[6] NEB, *In the Matter of Canadian Association of Petroleum Producers, Application dated 12 November 2004 requesting a review of Board Decision RH-2-2004 Phase I*, Reasons for Decision RH-R-1-2005 (May 2005) [RH-R-1-2005].

[7] The NEB first addresses the threshold question of whether a review is warranted. If so, only then does the NEB turn to the second question of whether to vary the original decision.

[8] *Supra* note 6 at 11.

[9] Rate of return on common equity.

CAPP argued that there were two distinct methodologies before the NEB in this proceeding: the first being the NEB's traditional framework and the second being the approach put forward by TCPL, which focused on a total return framework. CAPP favoured the traditional framework used by the NEB in previous decisions, RH-2-94 and RH-4-2001,[10] as it involved separate determinations of ROE and of deemed capital structure. In CAPP's view, the RH-4-2001 Decision should serve as the baseline and the NEB should assess what changes of significance, if any, have occurred since 2001, with TCPL having the burden to prove whether such changes justify a change in capital structure.

CAPP argued that the essence of TCPL's total return comparisons approach was flawed because to arrive at total return, one must make a finding on the ROE, which was not an issue in this case, as TCPL chose not to file an application for review of the ROE stemming from the RH-2-94 Formula.

On 29 April 2005, the NEB approved an increase in the Mainline common equity ratio of TCPL from 33 to 36 percent effective 1 January 2004. The NEB agreed with CAPP's methodology and confirmed that, historically, it has examined the elements that are considered in determining total return separately rather than looking at specific evidence regarding overall return. The NEB concluded that, overall, the business risk to which the Mainline was exposed had increased since the last assessment of TCPL's cost of capital in the RH-4-2001 hearing as a result of increases in supply risk and competitive risk. Therefore, an increase in TCPL's common equity ratio was warranted to ensure that the Mainline continued to maintain its financial integrity and its ability to attract capital on reasonable terms and conditions. The overall equity return and return on capital resulting from the RH-2-94 Formula and a common equity ratio of 36 percent were in line with the returns of those Canadian pipelines found to be of comparable risk.[11]

The NEB was satisfied that the decisions reached in the Phase II Decision, in combination with the Tolls and Tariff provisions that were the subject of Phase I of the hearing, would result in tolls that were just and reasonable for the 2004 Test Year.

2. RH-1-2005 — APPROVAL OF ENBRIDGE PIPELINES INC. APPLICATIONS FOR CONTRIBUTION OF FINANCIAL SUPPORT[12]

On 28 April 2005, the NEB approved (with reasons released on 9 June 2005) two applications submitted by Enbridge Pipelines Inc. (Enbridge) for the implementation of a Non-Routine Adjustment (NRA) for recovery of amounts from Canadian pipeline tolls

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[10] NEB, *Multi-Pipeline Cost of Capital Proceeding*, Reasons for Decision RH-2-94 (revised March 1997) [RH-2-94] and NEB, *In the Matter of TransCanada PipeLines Limited, Proceeding on TransCanada's 2001 and 2002 Tolls and Tariff Application*, Reasons for Decision RH-1-2001 (November 2001).

[11] See the NEB's cautious use of comparisons of ratios in RH-2-2004, *supra* note 4 at 70: "In summary, while the Board finds the comparisons with Alliance, M&NP and Westcoast informative and qualitatively useful, the different circumstances of these pipelines make it difficult to use these comparisons to arrive at a definitive equity ratio for the Mainline."

[12] NEB, *In the Matter of Enbridge Pipelines Inc., Applications dated 7 January 2005 and 8 February 2005 for orders pursuant to Part IV of the National Energy Board Act*, Reasons for Decision RH-1-2005 (June 2005) [RH-1-2005].

related to its U.S. Spearhead Pipeline. Enbridge requested US$10 million per year for five years from shippers on its Canadian mainline system for each of its applications to:

(a) extend service through the Spearhead Pipeline, which runs from Chicago, Illinois to Cushing, Oklahoma (the Spearhead Pipeline application); and

(b) extend service to the U.S. Gulf Coast through the reversal of flow of Mobil Pipe Line Company's (Mobil) pipeline, which runs from the Patoka Station, Marion County, Illinois to the Corsicana Station, Navarro County, Texas (the 20 Pipeline Reversal application).

In its Reasons for Decision, the NEB found that it was generally accepted that western Canadian crude oil production would continue to grow due to the development of the oil sands, noting that evidence tendered by Enbridge and CAPP indicated that by 2015, western Canadian crude oil supply could increase by one million barrels per day (b/d) (158,983 cubic metres per day (m^3/d)) as compared to 2004. While there appeared to be sufficient capacity on the Enbridge system to accommodate some incremental volumes, the evidence also indicated that the northern U.S. Petroleum Administration for Defense District (PADD) II markets were virtually saturated with Canadian heavy crude oil and that new markets are required.

The NEB concluded that transportation access to additional markets is required to accommodate growing supplies from the oil sands. The Cushing and U.S. Gulf Coast markets with their large refining capacity (almost seven million b/d) and ability to process crude oil from the oil sands appeared attractive to many producers. A number of parties emphasized to the NEB the importance of a timely response to this market access issue.

The NEB considered a number of factors in its assessment of the Enbridge applications. These included: the growing oil sands production, market requirements, timeliness of new market access, impacts on existing shippers, level of shipper support, and potential system benefits. The NEB determined that the need to provide market access was immediate and would benefit all shippers on Enbridge's Canadian system. Enbridge and Mobil indicated that they wished to begin work without delay and to have their pipelines in service by the end of 2005 or the first quarter of 2006.

The NEB accepted the evidence that the U.S. Federal Energy Regulatory Commission's (FERC) traditional cost-of-service tolls on the reversed pipelines would not attract shippers, and that to be economically feasible, the proposed projects required an innovative toll structure and financial support in order to penetrate the new markets. The NEB also noted that CAPP had agreed to the provision of financial support for the proposed projects and, as a result of the open seasons for capacity on the reversal projects, shippers committed to significant levels of firm transportation. The NEB further accepted the evidence that the respective pipelines would bear the risk that the market demand for Canadian crude oil will develop so that sufficient volumes would be attracted to the reversal projects after the five-year term of the proposed NRAs. Therefore, no further support from Enbridge shippers would be required.

The NEB concluded that there was an adequate level of market support for the proposed reversal projects, the associated tolling structures, and the collection of financial support through tolls on the Enbridge Canadian mainline. The NEB also noted that Enbridge had acted prudently to ensure that its system shippers would not bear any risks beyond the five-year term of the support agreements.

The NEB found it reasonable and prudent for Enbridge to enter into the proposed contractual commitments to provide financial support to the reversal projects, since the costs would result in general benefits to the Enbridge system and its shippers. Therefore, the NEB found it reasonable that the extra-territorial costs be included in the Enbridge annual revenue requirement for recovery from all its shippers.

The NEB did not find persuasive the argument of one of the intervenors, Flint Hills Resources (Flint), that it lacked authority to approve the recovery of the proposed extra-territorial costs in tolls on the Canadian system. Having found that the costs would be reasonably and prudently incurred in relation to the operation of the Canadian system, the NEB concluded it would be inconsistent and contrary to well-established rate-making principles to find that the same costs could not be recovered from the users of that system.

Flint applied to the Federal Court of Appeal for leave to appeal the NEB's decision and was granted leave on 31 August 2005. The appeal, filed by Flint and the Respondents (Enbridge, Mobil, Imperial Oil, National Energy Board, and CAPP), was dismissed on 4 October 2006.[13]

3. RHW-1-2005 — APPROVAL OF WESTCOAST ENERGY INC. APPLICATION FOR FIRM TRANSPORTATION SERVICE ENHANCEMENTS IN ZONES 3 AND 4[14]

On 10 November 2005, the NEB approved an application by Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission (Westcoast), for approval of certain firm transportation service enhancements in Zone 3 (Mainline Transportation North) and Zone 4 (Mainline Transportation South). The service enhancements were term differentiated firm service tolls, authorized overrun service (AOS), and daily cross-corridor crediting in Zone 3. Westcoast requested approval to increase the value of firm service to both existing and potential shippers and to encourage higher levels of firm service contracting.

A few participants had voiced objections in respect of certain aspects of the application. For example, CAPP did not support Westcoast's AOS proposal, expressing the view that AOS is nothing more than priority interruptible service and is not an attribute of firm service. Also, both the "Export Users Group" and Terasen Gas companies expressed concern regarding Westcoast's proposed elimination of the current restriction on cross-corridor crediting.

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13 *Flint Hill Resources Ltd. v. Canada (National Energy Board)*, 2006 FCA 320, 354 N.R. 297.

14 NEB, *In the Matter of Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission, Application dated 30 June 2005 for Approval of Certain Firm Service Enhancements in Zones 3 and 4*, Reasons for Decision RHW-1-2005 (November 2005) [RHW-1-2005].

4. COMMENCEMENT OF NEB HEARING AND JOINT REVIEW PANEL HEARING FOR MACKENZIE GAS PROJECT

On 25 January 2006, the NEB commenced its public hearing on the Mackenzie Gas Project (the Project), a proposed $6.8 billion natural gas project that includes a pipeline to transport natural gas to northern Alberta, a pipeline to transport natural gas liquids to Norman Wells, Northwest Territories, three onshore natural gas fields, a gathering system to transport production from such fields to the transmission line, a processing facility in Inuvik, Northwest Territories where natural gas liquids would be separated from the natural gas for shipping, compressor stations, and a heater station. The NEB process was commenced pursuant to applications made by the proponents of the Project: Imperial Oil Resources Ventures Limited (IORVL), Mackenzie Valley Aboriginal Pipeline Limited Partnership, Imperial Oil Resources Limited, ConocoPhillips Canada (North) Limited, ExxonMobil Canada Properties, and Shell Canada Limited. The NEB intends to make a decision on whether the Project is in the public interest only after receiving the report of the Joint Review Panel (as described below) and the response to it from the federal government.

The NEB's hearing is scheduled to take place in a number of locations in the North, including Norman Wells, Fort Good Hope, Tulita, Yellowknife, Fort Providence, High Level, Hay River, Wrigley, Fort Simpson, Colville Lake, and Tuktoyaktuk, and is slated to end in Inuvik in mid-December 2006.[15]

The NEB's schedule was coordinated with the environmental assessment (EA) process currently being conducted by the Joint Review Panel (JRP) for the Mackenzie Gas Project,[16] a seven-member, independent body mandated by the Agreement for an Environmental Impact Review of the Mackenzie Gas Project[17] between the Mackenzie Valley Environmental Impact Review Board (the MVEIRB), the Inuvialuit, as represented by the Inuvialuit Game Council, and the federal Minister of the Environment, to evaluate the potential impacts of the Project on the environment and the lives of the people in the Project area. The inter-agency coordination between the NEB and the JRP reflects the 2002 federal Cooperation Plan, designed to reduce regulatory duplication and provide clarity of process.[18]

On 14 February 2006, the JRP began its public hearings. The focus of the JRP process is on the environmental, socio-economic, and cultural issues of the Project, with participation from some 35 parties that have received in total $1,670,054 from the Canadian Environmental Assessment Agency (CEAA) and the MVEIRB.[19] The JRP has encouraged

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15 See "National Energy Board to begin Mackenzie Gas Project hearing on 25 January 2006" (20 December 2005), online: NEB <www.neb-one.gc.ca/newsroom/releases/nr2005/nr0530_e.htm>.

16 See Schedule for the NEB Hearings, *ibid.*

17 See JRP, News Release, online: JRP <www.jointreviewpanel.ca/documents/JRPA_NewRelease.e_Aug18_04.pdf>.

18 The coordinated JRP/NEB hearing schedule is available at "What's New," online: Northern Gas Project Secretariat <www.ngps.nt.ca/WhatsNew.htm>.

19 See CEAA, MVEIRB, News Release, "Federal Funding Awarded to Participate in the Environmental Review of the Mackenzie Gas Project — Phase 3" (4 January 2006), online: Northern Gas Project Secretariat <www.ngps.nt.ca/documents/NewsRelease_PFPP3_Jan4_2006.pdf>. The recipients of participant funding are: Inuvialuit Regional Corporation; Joint Secretariat; Fisheries Joint Management Committee; Randal Boogie Pokiak; Gwich'in Tribal Council; Gwich'in Renewable Resource Board;

the submission of traditional knowledge during the hearing phase of its review to ensure that it contributes fully to the environmental impact assessment review of the proposed Project.[20]

a. Intervenor Motions and Actions

In parallel proceedings before the Federal Court of Canada, the Deh Cho First Nations, Lliidli Koe First Nations, Fort Simpson Métis Nation Local 59, Pehdzeh Ki First Nation, T'thek'ehdeli Ki First Nation, Ka'a'gee Tu First Nation, and Sambe K'e Dene Band (the Applicants) filed a motion requesting a broad range of documents from the Minister of the Environment that bear on the decision by the Minister, made on 3 August 2004, to establish the JRP to undertake the environmental impact assessment in connection with the Project.[21] On 15 March 2005, Prothonotary Hargrave of the Federal Court of Canada granted the motion, noting that although the descriptions of the documents that the Applicants sought came close to an "overly general request," they "do not cross the line by seeking wholesale production. Rather, the documents are requested in relation to various specific steps or phases in the process leading to the 3 August 2004 decision to establish the Joint Review Panel."[22]

The Deh Cho obtained an out-of-court settlement of their first lawsuit against the federal government last fall and received $31 million to finance economic development and pay for negotiations and participation in the pipeline review.[23]

On 27 February 2006, another court proceeding was commenced by the Deh Cho First Nation (Deh Cho) in the Supreme Court of the Northwest Territories, challenging the 27 January 2006 decision by the MVEIRB, alleging that the MVEIRB had exceeded its authority by removing Measure 10 from the MVEIRB's Report of Environmental Assessment and Reasons for Decision on IORVL's Deh Cho Geotechnical Program (EA 03-009), dated 18 February 2005. Measure 10 required IORVL to reach agreements with Deh Cho communities in respect of social and cultural impacts. The Deh Cho alleged that it was

Nihtat Gwich'in Council/Inuvik Native Band; Ayoni Keh Land Corporation; K'ahsho Got'ine District Land Corporation; Tulita Yamouria Community Secretariat; Deline Land Corporation; Dene Tha' First Nation; North Slave Métis Alliance; West Point First Nation; Acho Dene Koe; Pehdzeh Ki First Nation; Deh Gah Gotie Dene Council; Lliidli Koe First Nation; Fort Simpson Métis Nation; K'atlodeeche First Nation; Sambaa K'e Dene Band; Fort Providence Métis Council; Town of Inuvik; Town of Hay River; City of Yellowknife; Village of Fort Simpson; Enterprise Settlement Corporation; Hamlet of Fort McPherson; Canadian Arctic Resources Committee; NGO Coordinating Committee; Arctic Indigenous Youth Alliance; Alternatives North Coalition; Nature Canada; World Wildlife Fund; and Sierra Club of Canada.

20 See JRP, Announcement, "Traditional knowledge in the environmental impact assessment of the proposed Mackenzie Gas Project" (16 May 2005), online: JRP <www.jointreviewpanel.ca/documents/JRPPN8_TK_May16_ 2005_final.pdf>.

21 *Deh Cho First Nations v. Canada (Minister of Environment)*, 2005 FC 374, 13 C.E.L.R. (3d) 27.

22 *Ibid.* at para. 16.

23 "Foes of $7B pipeline sue for their rights: Holdout tribe back in court" *Calgary Herald* (8 March 2006) D.1.

unfair of the MVEIRB to make a decision based on information the Deh Cho did not have and to which they were not given the chance to respond.[24]

In a separate proceeding, the Dene Tha' First Nation (Dene Tha'), which has traditional land claims in northern Alberta and the southern Northwest Territories, filed an application for judicial review on 17 May 2005, claiming an ongoing failure of the federal Ministers of the Environment, Fisheries and Oceans, Indian and Northern Affairs, and Transport to comply with their fiduciary and constitutional duties under s. 35 of the *Constitution Act, 1982*[25] to consult with the Dene Tha' and accommodate their Aboriginal and treaty rights in relation to the environmental and regulatory review process for the Project.[26] The judicial review application was to be heard by the Federal Court of Canada on 19 June 2006.

On 29 December 2005, the Dene Tha' filed a motion with the JRP requesting that the start of the JRP hearings be delayed until after the Federal Court makes a decision on any motions of the Attorney General of Canada related to the Dene Tha' judicial review application. The JRP denied such motion, holding that:

> the matters set out ... in the Application are beyond the jurisdiction of the Panel and are best resolved by the courts.... The Panel notes there are significant uncertainties associated with timing and resolution of these issues whether by way of litigation or by negotiated settlement. Delay by the Panel in the commencement of its public hearings will not cure the alleged defects raised by the [Dene Tha'] in its Application.[27]

On 6 January 2006, the Attorney General of Canada brought a motion to stay the judicial review proceeding pursuant to s. 50(1) of the *Federal Courts Act*.[28] On 9 March 2006, the Federal Court denied the motion brought by the Attorney General of Canada to stay this proceeding.[29] On 16 March 2006, the Attorney General filed a Notice of Appeal for this interlocutory decision with the Federal Court of Appeal.[30]

The Mackenzie Explorer Group has applied for an order declaring the gathering system to be subject to Part IV of the *NEB Act* (toll and tariff regulation), along with the transmission pipeline, and an order directing IORVL to apply thereunder. It has drawn on constitutional jurisprudence and principles of statutory interpretation in its argument, which has been resisted by the Project proponents. The NEB received written submissions and heard oral arguments on 2 June 2006. A decision is pending.

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24 *Grand Chief Herb Norwegian suing on his own behalf and on behalf of all Members of the Dehcho First Nations and the Dehcho First Nations v. Mackenzie Valley Environmental Impact Review Board and Imperial Oil Resources Ventures Limited*, filed in the Supreme Court of the Northwest Territories on 27 February 2006, Court File no. S-0001-CV2006000049.

25 Being Schedule B to the *Canada Act 1982* (U.K.), 1982, c. 11.

26 *Dene Tha' First Nation v. Canada (Minister of Environment)*, 2006 FC 1354, 25 C.E.L.R. (3d) 247.

27 JRP, Letter re: DTFN Motion filed with the JRP on 29 December 2005 to Robert C. Freedman, counsel to the DTFN (6 January 2006), online: Northern Gas Project Secretariat <www.ngps.nt.ca/Upload/Joint%20Review%20Panel/060106_JRP_to_Freedman_Motion.pdf> at 2.

28 R.S.C. 1985, c. F-7.

29 *Dene Tha' First Nation v. Canada (Minister of Environment)*, 2006 FC 307, 21 C.E.L.R. (3d) 27.

30 See Notice of Appeal (Appeal Court File No. A-113-06) and Proceedings Queries.

5. RHW-2-2005 — CORAL ENERGY CANADA INC. APPLICATION TO MODIFY THE FIRM TRANSPORTATION RISK ALLEVIATION MECHANISM FOR THE TRANSCANADA MAINLINE[31]

On 24 February 2006, the NEB announced its approval of the application of Coral Energy Canada Inc. (Coral) to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) for the TransCanada Mainline and directed TransCanada to modify its Mainline Transportation Tariff to reflect this decision.

FT-RAM is a service enhancement being provided on a pilot basis to TransCanada's Long Haul[32] Firm Transportation (FT) shippers since 1 November 2004. The FT-RAM pilot program allows Long Haul FT shippers to apply unutilized FT demand charges against their cost of interruptible transportation (IT) service. Coral's application, submitted on 30 September 2005, proposed that the FT-RAM pilot program be extended to Short Haul[33] FT contracts in situations where a shipper holds a short-haul contract whose receipt point is also the delivery point of a Long Haul FT contract held by the same shipper.

The NEB issued a Hearing Order on 8 November 2005 and considered Coral's application through a written public hearing followed by oral argument. During final argument, certain parties[34] suggested that Coral's application was either an attempt to vary an NEB-approved settlement or an attempt to abrogate a pre-existing agreement among members of the TransCanada Mainline Tolls Task Force (TTF). In this context, it was suggested that it would be inappropriate for the NEB to approve any modifications to the existing FT-RAM Pilot until the terms and conditions underlying previous TTF Resolutions were fulfilled. The most notable areas of concern were provisions in the original Resolutions that: (i) restricted the pilot to long haul contracts; and (ii) established that an impact report would be filed by TransCanada after April 2006.

In its decision, the NEB determined that the TTF Resolutions had not been filed with the NEB as settlements pursuant to its Guidelines for Negotiated Settlement. Therefore, the NEB held that Coral's application was not an attempt to inappropriately vary or modify the terms of a settlement. The NEB held that Coral's proposal was conceptually consistent with the FT-RAM pilot project's goal of motivating the retention and new contracting of FT transportation. The NEB noted that it did not receive any compelling evidence that Coral's proposal would have a significant negative impact on any individual shipper or on the system as a whole and, therefore, approved Coral's proposed modification to the existing FT-RAM pilot project. The proposed modification was effective from 1 April 2006 and terminated on 31 October 2006.

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31 NEB, *In the Matter of Coral Energy Canada Inc., Application for Approval of Modifications to the Firm Transportation Risk Alleviation Mechanism (FT-RAM) Pilot for the TransCanada PipeLines Limited Mainline*, Reasons for Decision RHW-2-2005 (February 2006) [RHW-2-2005].

32 "Long Haul" is defined as "[a] contract whose primary receipt point originates at Empress, Alberta or in Saskatchewan on the TransCanada Mainline" (*ibid.* at iv).

33 "Short Haul" is defined as "[a] contract originating at locations other than Empress or a Saskatchewan receipt point on the TransCanada Mainline" (*ibid.*)

34 See, *e.g.*, the summary of the positions of the Industrial Gas Users Association and Enbridge Gas Distribution Inc., *ibid.* at 5-6.

6. RHW-3-2005 — CENTRA TRANSMISSION HOLDINGS INC.[35]

On 5 August 2005, Centra Transmission Holdings Inc. (CTHI) filed an application with the NEB pursuant to Part IV of the *NEB Act* seeking increased tolls for transportation service on its pipeline system effective 1 August 2005 (later changed to 9 September 2005). CTHI's tolls were last revised effective 1 May 1995. CTHI is a "Group 2" company for NEB purposes. It is unusual for a Group 2 company to come before the NEB in a hearing on rate or tariff matters.[36]

On 23 March 2006, the NEB approved the application for revised tolls made by CTHI. In its Reasons for Decision, the NEB approved CTHI's proposed Total Cost of Service for 2005, subject to a reduction of income taxes that will occur because of the NEB's decision not to allow CTHI to collect the income tax component of its proposed surcharge as part of its demand toll, but rather through the surcharge. The NEB also found the cost of capital applied for by CTHI to be reasonable, and approved a rate of return on common equity of 12.25 percent[37] and an equity component of 40 percent. The NEB approved CTHI's proposed surcharge methodology for recovering the outstanding balance in its fuel gas deferral account, but denied the recovery of costs associated with line heaters in the deferred balance.

The NEB also approved CTHI's projected costs for its integrity management program and directed CTHI to begin discussions with its shippers to address shippers' concerns expressed during the hearing.

B. ALBERTA ENERGY AND UTILITIES BOARD

The Alberta Energy and Utilities Board (AEUB) is successor to the Energy Resources Conservation Board, the Public Utilities Board, and the Alberta Geological Survey.[38] Under its mandate as set out in its enabling statute, the *Alberta Energy and Utilities Board Act*,[39] and governed by some 30 statutes, including the *Energy Resources Conservation Act*,[40] *Gas Resources Preservation Act*,[41] *Gas Utilities Act*,[42] *Oil and Gas Conservation Act*,[43] *Oil Sands Conservation Act*,[44] and *Pipeline Act*,[45] the AEUB adjudicates and regulates matters related to energy and utilities within Alberta to ensure that the development, transportation, and monitoring of the province's energy resources are in the public interest. In addition, the AEUB balances the interests of customers and investor-owned utilities in establishing rates, terms, and conditions of services. The AEUB provides these services through its application

35 NEB, *In the Matter of Centra Transmission Holdings Inc., Application for revised tolls effective 1 August 2005*, Reasons for Decision RHW-3-2005 (March 2006) [RHW-3-2005].
36 In this case, the NEB adopted a combination of written and oral (telephone submissions) processes.
37 Note that the formula-driven ROE for Group 1 companies for 2006, following NEB Decision RH-2-94 (*supra* note 10), was 8.88 percent.
38 For background on the AEUB and access to AEUB decisions, guidelines, directives, and other releases to the industry, see online: AEUB <www.eub.gov.ab.ca>.
39 R.S.A. 2000, c. A-17 [*AEUB Act*].
40 R.S.A. 2000, c. E-10.
41 R.S.A. 2000, c. G-4.
42 R.S.A. 2000, c. G-5 [*GUA*].
43 R.S.A. 2000, c. O-6.
44 R.S.A. 2000, c. O-7.
45 R.S.A. 2000, c. P-15.

and hearing process, standards setting and regulation, monitoring, surveillance, and enforcement.

The following is an examination of the more significant oil and gas related decisions made by the AEUB in the past year, in chronological order.

1. DECISION 2005-060: *COMPTON PETROLEUM CORPORATION*[46]

The AEUB conducted an extensive public hearing from 11 January to 4 March 2005 to consider nine related applications by Compton Petroleum Corporation (Compton) related to its North Okotoks Horizontal Well Program, located 4.5 km southeast of the nearest community in Calgary; to drill six horizontal sour gas wells seeking gas reserves containing 35.6 percent hydrogen sulphide (H_2S); to construct and operate associated surface facilities; to reduce the emergency planning zone (EPZ) to 4 km, with a corresponding emergency awareness zone of 8 km; and to implement the associated emergency response plan (ERP). Compton also applied for a special well spacing unit.

The AEUB acknowledged that these sour gas wells, given their H_2S content of 35.6 percent, present a hazard during drilling, completion, and production operations, but a low level of risk. Given the proposed location of the applied-for wells in proximity to densely populated areas, the AEUB adopted a particularly cautious approach with respect to questions of public safety. In order for well licences to be issued, the AEUB required approval of the associated technical drilling and completion programs, as well as the ERP.

On 22 June 2005, the AEUB held that the proposed wells can be drilled, completed, and operated safely; however, the issuance was conditional on the AEUB's approval of Compton's ERP. The AEUB denied Compton's application for the reduced EPZ. Instead, the AEUB determined that an EPZ of 9.7 km — comprised of a 5 km evacuation zone and a 4.7 km sheltering zone — would be appropriate. The AEUB also required Compton's ERP to incorporate a collaborative command approach with the municipalities and the Calgary Health Region for public protection measures within and beyond the EPZ and that it be submitted by 3 January 2006. The AEUB's decision was subject to numerous other conditions, directions, and commitments.

On 21 December 2005, the AEUB denied an application from Compton to extend the deadline for submitting its ERP to 1 September 2006. However, the AEUB had indicated it would accept a draft ERP on 3 January 2006 and continue with the process thereafter. On 4 January 2006, the AEUB advised Compton that the applications had been closed due to Compton's failure to file its ERP by the deadline of 3 January 2006.[47]

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46 *Applications for Licences to Drill Six Critical Sour Natural Gas Wells, Reduced Emergency Planning Zone, Special Well Spacing, and Production Facilities, Okotoks Field (Southeast Calgary Area)* (22 June 2005).

47 See News Release 2006-01, "EUB Closes Compton Critical Sour Gas Well Applications" (4 January 2006), online: AEUB <www.eub.gov.ca/docs/new/newsrel/2006/nr2006-01.pdf>.

2. DECISION 2006-007: *ADVANTAGE OIL & GAS LTD.*[48]

On 7 February 2006, the AEUB released its decision denying the applications by Advantage Oil & Gas Ltd. (Advantage) for a multiwell oil battery licence and two multiwell oil satellite licences. The AEUB noted that in the face of significant concern and opposition by its neighbours, Advantage chose to apply for the multiwell oil battery at the 5-13 location rather than assessing any alternate locations.

The AEUB concluded that Advantage had not conducted adequate personal consultations with the intervenors and the community regarding the best location for the multiwell oil battery and why it preferred certain locations over others. It was not appropriate for Advantage to conclude that it could rely on the multiwell gas battery Licence No. F-28064 as the basis for a multiwell oil battery. Advantage should have seriously evaluated other sites within the field to address the concerns raised by the intervenors and should have entered into serious discussions with them. A detailed comparison of alternate sites may have demonstrated that the 5-13 location was the most appropriate; however, based on the evidence before it, the AEUB was unable to reach that conclusion. The AEUB denied the application for the multiwell oil battery without prejudice to any future applications.

The AEUB expressed concerns about the intervenors' serious misunderstanding in respect of notification, personal consultation, evacuation, and emergency response planning requirements. The AEUB believed that this misunderstanding resulted primarily from the failed effort initially by Defiant Energy Corporation, the corporate predecessor to Advantage, and later by Advantage with respect to participant involvement.

3. DECISION 2006-010: *NOVA GAS TRANSMISSION LTD.*[49]

On 15 April 2005, NOVA Gas Transmission Ltd. (NGTL) filed a 2005 Phase II General Rate Application. In it, NGTL fulfilled the AEUB's earlier direction to file a fully allocated Cost of Service Study, an updated Distance of Haul study, an updated Cost of Haul study, and rate design alternatives for the AEUB's consideration, including an allocation of transmission costs "greater than zero" to the intra-Alberta delivery service rate. At issue for the AEUB, among other things, was the continued appropriateness of intra-Alberta deliveries on NGTL free of demand charges, in the presence of competition for those volumes from others such as ATCO Pipelines (ATCO).

NGTL conducted the studies, generated alternatives, and filed the requested material, but preferred that the existing rate design be maintained.

ATCO commissioned and filed its own studies, as did the Industrial Gas Consumers Association of Alberta (IGCAA). ATCO argued for an increase to cost accountability on NGTL by increasing its intra-Alberta rate while the IGCAA argued for a reduction in the full-path rate for Alberta customers — a continuance of the intra-Alberta delivery demand

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48 *Applications for a Multiwell Oil Battery Licence and Two Multiwell Oil Satellite Licences, Chip Lake Field* (7 February 2006).

49 *2005 General Rate Application, Phase II* (21 February 2006).

charge at zero and a reduction in the firm receipt toll, shifting costs predominantly to export shippers. Export shippers (WEG)[50] resisted the proposed changes, as did the CAPP.

In a surprisingly brief decision (given the level of debate and volume of evidence adduced at the hearing), the AEUB elected to go with the majority and maintain the status quo rate design by denying all proposed changes. However, the AEUB displayed some discomfort in doing so.

The AEUB found some merit in ATCO's alternate rate design that would have increased intra-Alberta service tolls (for NGTL's "FT-A" service), but ultimately discounted those proposals because: (1) ATCO is a competitor of NGTL and the proposals would have advantaged ATCO in that competition; and (2) ATCO said its proposals would benefit the core customers of the province, yet core customers appearing before the AEUB advocated the status quo. Core customers preferred that the AEUB adopt a different mechanism to manage the pipe-on-pipe competition, rather than adjusting the rate designs of both, to ensure parity of cost accountability on the two systems. It preferred the objective be managed through a "least cost alternative" approach to facilities additions.

The AEUB also found some merit in the IGCAA's proposals. But in the end the AEUB was not persuaded the IGCAA had proved its approach to be superior to NGTL's. The AEUB was persuaded by the positions of the ex-Alberta markets and the producers that between them they pay, directly or indirectly, the overwhelming majority of NGTL's revenue requirement.

The AEUB considered the IGCAA evidence to be worthy of further consideration and so approved continuance of the status quo rate design just "for the 2005 test period." Technically, that is all the AEUB could have done, but the wording used by the AEUB on that point suggests it still remains open to being persuaded to move off the existing rate design.

The AEUB was reluctant to make a change in the face of such diverse approaches, all in their own way appearing to it as having at least some legitimacy. It encouraged "a collaborative process among the parties"[51] on the following matters:

(a) WEG's suggestion of delivery point-specific, or at least border-specific, rates;

(b) IGCAA's suggestion of changes to the short haul rate, that is for NGTL's "points-to-point" or "FT-P" service;

(c) NGTL's suggestion of more closely aligning costs of specific projects under the Extension Annual Volume (EAV) calculation; and

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50 The "Western Export Group" (WEG), formed to participate in the process, is comprised of nine shippers exporting at the Alberta-B.C. export point that transmit, distribute, or consume gas along the western tier of North America.

51 *Supra* note 49 at 10.

(d) ATCO's and WEG's proposals to bring greater cost accountability to the NGTL rate structure.

The AEUB also restated its intent to "conduct a review process on issues that are considered to constitute competitive issues."[52] The AEUB indicated that it "intends to canvass interested parties by June 2006 to assist in developing the scope for this process."[53] Its earlier comments suggest that the focus of this debate will be to attempt to resolve the issue of how to properly regulate competing gas pipelines by decisions on facilities proposals, instead of by changing their rate designs.

4. APPEAL OF AEUB DECISIONS

Pursuant to ss. 26(1) and (2) of the *AEUB Act*, an appeal lies from the AEUB to the Alberta Court of Appeal on questions of jurisdiction or on questions of law, with leave to appeal obtained from a judge of the Court of Appeal on an application made within 30 days from that order, decision, or direction. Of the various appellate decisions in the past year, the following six are noteworthy.

a. *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*

On 9 February 2006, the Supreme Court of Canada released its decision in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*.[54] This decision finally clarifies the limits on the AEUB's powers to distribute any net gain from a property sale by a utility to its ratepaying customers.

ATCO is a public utility in Alberta that delivers natural gas. ATCO Gas - South (AGS), a division of ATCO, applied to the AEUB pursuant to s. 26(2) of the *GUA*,[55] for approval of the sale of the AGS properties (land and buildings) known as the Calgary Stores Block. ATCO took the position that the property was no longer used or useful for the provision of utility services and the sale would not cause any harm to its customers. ATCO requested that the AEUB approve the sale transaction, as well as the proposed disposition of the sale proceeds: (i) to retire the remaining book value of the sold property; (ii) to recover the disposition costs; and (iii) to recognize that the balance of the profits resulting from the sale should be paid to ATCO's shareholders. The City of Calgary, which represented the customers' interests, opposed ATCO's proposed disposition of the sale proceeds to shareholders.

The AEUB notified the parties that it would follow a two step process: (1) the AEUB would consider whether the sale should be approved; and (2) if the sale was approved, the AEUB would deal with the allocation of the sale proceeds and any other relevant issues.

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52 *Ibid.* at 11.

53 *Ibid.*

54 2006 SCC 4, [2006] 1 S.C.R. 140.

55 *Supra* note 42. Pursuant to s. 26(2) of the *GUA*, the owner of a designated utility cannot issue any shares, sell, lease, mortgage, or otherwise dispose of or encumber its property, outside the ordinary course of business, without prior approval of the AEUB. ATCO Gas & Pipelines Ltd. is an owner of a designated utility (*Designation Regulation (Gas Utilities Act)*, Alta. Reg. 237/2005 [*Designation Regulation*]).

In its first decision, the AEUB approved the sale transaction on the basis that customers would not be exposed to the risk of financial harm as a result of the sale that could not be examined in a future proceeding.[56] In applying the "no-harm" test, the AEUB considered: (a) the potential impact that the disposition would have on both rates and customer service; (b) the prudence of the sale transaction (considering the purchaser's relationship to the vendor); (c) the tender or sale process followed; and (d) whether the availability of future regulatory processes might be able to address any potential adverse impacts that may arise from the transaction. The AEUB was satisfied that the "no-harm" test was met.

In its second decision,[57] the AEUB determined the allocation of net sale proceeds and held that it had the jurisdiction to approve a proposed disposition of sale proceeds subject to appropriate conditions to protect the public interest under s. 15(3) of the *AEUB Act*. The AEUB applied the "TransAlta formula," whereby the "windfall" realized when the proceeds of sale exceed the original cost could be shared between customers and shareholders, and accordingly, it allocated a portion of the net gain on the sale to the customers.

ATCO appealed the AEUB's decision to the Alberta Court of Appeal, arguing that the AEUB did not have any jurisdiction to allocate the proceeds of sale to the customers and that the proceeds should have been allocated entirely to the shareholders. In ATCO's view, allowing customers to share in the proceeds of sale would result in them benefiting twice, since the retiring and withdrawing of the property's net book value from the rate base would already reduce the customers' rates. The Court of Appeal allowed ATCO's appeal, set aside the AEUB's decision, and referred the matter back to the AEUB, directing it to allocate the proceeds of the property sale that exceeded the original cost to ATCO.[58]

The City of Calgary appealed the Court of Appeal's decision to the Supreme Court of Canada, maintaining that the AEUB has jurisdiction to allocate a portion of the net gain on the sale of a utility property to the rate-paying customers. ATCO cross-appealed, contending that the AEUB has no jurisdiction to allocate any of ATCO's proceeds from the sale to customers.

In a majority (4-3) decision, the Supreme Court of Canada dismissed the City of Calgary's appeal and allowed ATCO's cross-appeal. The Supreme Court upheld the Court of Appeal's decision in part, holding that it did not err when it held that the AEUB acted beyond its jurisdiction by misapprehending its statutory and common law authority. However, the Supreme Court held that the Court of Appeal should have gone on to conclude that the AEUB has no jurisdiction to allocate any portion of the proceeds of sale of the property to ratepayers — not the excess over original cost on the difference between net book value and original cost. Thus, the Supreme Court set aside the AEUB's decision and referred the matter back to the AEUB for approval of the sale of the property belonging to ATCO, recognizing that the proceeds of the sale belong to ATCO.

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56 AEUB, Decision 2001-78: *ATCO Gas & Pipelines Ltd., Disposition of Calgary Stores Block and Distribution of Net Proceeds — Part 1* (24 October 2001).

57 AEUB, Decision 2002-037: *ATCO Gas & Pipelines Ltd., Disposition of Calgary Stores Block and Distribution of Net Proceeds — Part 2* (21 March 2002).

58 *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2004 ABCA 3, 339 A.R. 250.

The Supreme Court held that the AEUB's seemingly broad powers under its constituent legislation to make any order and to impose any additional conditions necessary in the public interest have to be interpreted within the entire context of those statutes, which are meant to balance the need to protect consumers, as well as the property rights retained by owners as recognized in a free market economy. Therefore, the limits of the AEUB's powers are grounded in its main function of fixing just and reasonable rates and protecting the integrity and dependability of the supply system. The rates paid by customers did not incorporate acquiring ownership or control of the utility's property.

The Supreme Court observed that the AEUB's regulatory responsibility was to maintain a tariff that enhanced the economic benefits to customers and investors of the utility. This regulatory arrangement did not change the private nature of the utility. The fact that the utility was given the opportunity to make a profit on its services and a fair return on its investment in its property should not stop the utility from benefiting from the sale of property. The power to allocate sale proceeds was absent from the explicit language of the legislation, and it could not be implied from the statutory regime as necessarily incidental to the explicit powers.

b. *Stiles Estate v. Alberta (Energy & Utilities Board)*[59]

This was a decision by the Alberta Court of Appeal released on 30 September 2005 in respect of an application by the Stiles Estate (the Estate) for leave to appeal a decision of the AEUB, which had denied the Estate's request for review of an earlier decision to grant Esprit Exploration Ltd. (Esprit) a licence to drill a well on land adjoining lands owned by the Estate. The Estate argued that Esprit did not give proper notice of its licence application because it notified the widow that occupied the lands, but failed to notify the executor of the Estate. The AEUB denied the request for a review on the basis that Esprit complied with the notification and consultation requirements or, alternatively, that the Estate lacked standing to object to the licence because it was not directly and adversely affected thereby. The Estate sought leave to appeal on the grounds that the AEUB treated it unfairly in the denial of its request for a review, and that its finding that the Estate lacked standing constituted an error in law.

The Court of Appeal dismissed the application as no serious arguable issue of law or jurisdiction was raised by the Estate. The AEUB did not deny the Estate procedural fairness in the manner in which it dealt with the request for a review. The test applied by the AEUB relating to the Estate's standing was correct. The finding that the Estate was not directly affected by the licence grant was a finding of fact and was therefore not reviewable on appeal.

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[59] 2005 ABCA 308, 53 Alta. L.R. (4th) 235.

c. *Bartlett v. Alberta (Energy & Utilities Board)*[60]

This was a decision by the Alberta Court of Appeal released on 12 October 2005 in respect of an application by several individuals for leave to appeal two decisions of the AEUB denying their request for an oral hearing with respect to the application by BA Energy Incorporated (BA Energy) to construct and operate an Upgrader, and approving the application by BA Energy. The applicants were residents who lived close to the proposed Upgrader. They were members of a group that had been granted intervenor status in the application by BA Energy for approval by the AEUB. The lawyer for the group had withdrawn the group's objection to the proposal. The applicants argued that they had not agreed to the withdrawal. The AEUB refused their request for an oral hearing and allowed BA's application for approval of the Upgrader. The applicants alleged that the AEUB committed errors of law and jurisdiction that raised serious issues for appeal. They argued that the AEUB could not properly carry out its mandate to determine the public interest without relevant information and failed to consider the effects of the proposed Upgrader.

The Court of Appeal dismissed the application, finding that the applicants were members of the group at all material times and were bound by its decision to participate in the negotiations and by the lawyer's decision to withdraw the group's objections to the proposal.

d. *Prairie Acid Rain Coalition v. Canada (Minister of Fisheries & Oceans)*[61]

This case is not an appeal of an AEUB decision, but is a relevant case as it discusses the importance of avoiding duplication of a federal *Canadian Environmental Assessment Act*[62] comprehensive study environmental assessment process, where a public hearing on the same project has already been held by the AEUB.

Decided by the Federal Court of Appeal on 27 January 2006, this case was an appeal from a chambers decision dismissing the application by the appellant, Prairie Acid Rain Coalition, for judicial review of a decision by the respondent, Department of Fisheries and Oceans Canada (DFO), which set the scope for an environmental assessment of an oil sands undertaking. The appellant claimed that the scope of the DFO's decision was too narrow, in that it only covered the destruction of a fish habitat, and not the entire oil sands undertaking that could affect such matters under federal jurisdiction as migratory birds, Aboriginal peoples, and other waters and fisheries. The DFO claimed that the undertaking was primarily subject to regulation by the Province of Alberta, which was already conducting an environmental assessment, and that the fish habitat was the only area of federal responsibility.

The Federal Court of Appeal dismissed the application holding that, as a matter of policy, it is sensible that undertakings with potential adverse environmental effects be subject to only one environmental assessment. In this case the Alberta provincial authorities were conducting an environmental assessment. It would have been inefficient for two assessments

60 2005 ABCA 340, 376 A.R. 192.
61 2006 FCA 31, [2006] 3 F.C.R. 610.
62 S.C. 1992, c. 37 [*CEAA*].

to be performed. The DFO has the discretion to determine the scope of the project under s. 15(1) of the *CEAA*. Therefore, it was both legally appropriate and efficient from a policy perspective for the DFO to rely on Alberta's performance of an environmental assessment.

e. *Calgary (City) v. Alberta (Energy & Utilities Board)*[63]

This was an application by the City of Calgary to the Alberta Court of Appeal for leave to appeal a decision of the AEUB extending the deadline imposed on Compton to elect to pursue its applications. No interested party was given notice of Compton's request that the AEUB extend the deadline. The City of Calgary had been granted intervenor status by the AEUB in the underlying application.[64] The AEUB and Compton responded that the extension was an administrative decision and that the City's rights had not been affected by the decision.

On 14 November 2005, the Alberta Court of Appeal allowed the application. The City had raised an arguable issue. It was not clear that the issue was moot. Given the AEUB's closing of Compton's sour gas well applications on 4 January 2006, as described above, this appeal was discontinued on 18 January 2006.[65]

f. *Dene Tha' First Nation v. Alberta (Energy & Utilities Board)*[66]

On 18 August 2005, the Supreme Court of Canada dismissed the application of the Dene Tha' First Nation (Dene Tha') for leave to appeal the judgment of the Alberta Court of Appeal,[67] with costs to the respondent Penn West Petroleum Limited (Penn West). The Court of Appeal had dismissed the Dene Tha's appeal from the AEUB's decisions dated 16 January 2003 and 15 April 2003, which had dismissed the Dene Tha's application to intervene in an application brought by Penn West for drilling and road licences on Crown land. When the AEUB issued Penn West licences for the wells and roads, the Dene Tha' applied to intervene. The AEUB decided that the Dene Tha' had not met the statutory test for intervention, which required it to prove that it might be directly and adversely affected.

The Court of Appeal held that Penn West had informed the Dene Tha' that it intended to drill a number of wells and put in some access roads on Crown land, showing precisely where the facilities were to be installed. None were to be within Dene Tha' reserve land.

The Court of Appeal confirmed that an appeal from the AEUB's decision lay only with respect to a question of law or jurisdiction. The AEUB did not err with respect to the question of whether the claimed right or interest being asserted was known in law, nor did it err on the factual question of whether the application by Penn West could directly and adversely affect those rights. Lastly, the Dene Tha' conceded that neither Penn West nor the

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63 2005 ABCA 384, [2005] A.J. No. 1828 (QL).
64 See the discussion of the underlying application and the AEUB decision, commencing at Part II.B.1, above.
65 Notice of Discontinuance, Docket No. 0501-0257-AC (18 January 2006).
66 (2005), 391 A.R. 398.
67 2005 ABCA 68, 363 A.R. 234.

AEUB had any duty in law to consult with those holding Aboriginal or treaty rights. The Court of Appeal observed:

> That concession is plainly correct today, though it may have been unclear for a time. At one point in oral argument, there was a stray reference to the Board as an "emanation" of the Crown, a characterization not argued elsewhere, and in our view inaccurate. In the 1930s the Privy Council condemned that term as vague and apt to mislead. A duty of the Crown to consult was not really raised before the Board, though one or two phrases in the solicitors' letters make stray reference to it.[68]

C. BRITISH COLUMBIA UTILITIES COMMISSION

Under its mandate as set out in the *Utilities Commission Act*,[69] the British Columbia Utilities Commission (BCUC) is responsible for ensuring that customers receive safe, reliable, and non-discriminatory energy services at fair rates from the utilities it regulates; that shareholders of these utilities are afforded a reasonable opportunity to earn a fair return on their invested capital; and for approving the construction of new facilities planned by utilities and their issuance of securities. The BCUC also reviews energy-related matters referred to it by the Cabinet of the Government of British Columbia. These inquiries usually involve public hearings, followed by a report and recommendations to Cabinet.[70] In addition, under Part 7 of the *Pipeline Act*,[71] the BCUC establishes tolls and conditions of service for intraprovincial oil pipelines.

1. BCUC ORDER NO. G-116-05: *IN THE MATTER OF AN APPLICATION BY KINDER MORGAN, INC. AND 0731297 B.C. LTD. FOR THE ACQUISITION OF COMMON SHARES OF TERASEN INC. DECISION*[72]

On 17 August 2005, Kinder Morgan Inc. and 0731297 B.C. Ltd. (collectively, KMI) applied to the BCUC pursuant to s. 54 of the *UCA* for approval of the acquisition of the common shares of Terasen Inc. (Terasen) by KMI (the Transaction).[73] On 10 November 2005, the BCUC issued an Order approving the Transaction. The granting of the Order is not significant because of any novel legal issues it addressed, but rather for the intense public

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68 *Ibid.* at paras. 24-25.

69 R.S.B.C. 1996, c. 473 [*UCA*].

70 For more information on the BCUC's mandate and access to its decisions, guidelines, directives, and other releases to the industry, see online: BCUC <www.bcuc.com>.

71 R.S.B.C. 1996, c. 364.

72 (10 November 2005).

73 The Transaction would cause KMI to have indirect control of Terasen Gas Inc. (TGI), Terasen Gas (Vancouver Island) Inc. (TGVI), Terasen Gas (Squamish) Inc. (TGS), Terasen Gas (Whistler) Inc. (TGW), and Terasen Multi-Utilities Services Inc. (TMUS). Each of TGI, TGVI, TGW, and TMUS are wholly-owned subsidiaries of Terasen. TGI owns all of the outstanding shares of TGS and TGS is an indirect wholly-owned subsidiary of Terasen. Each of TGI, TGVI, TGS, TGW, and TMUS (collectively, the Terasen Utilities) are public utilities regulated by the BCUC. Terasen also owns all of the outstanding shares of Terasen Pipelines (Trans Mountain) Inc. (TM). TM is not regulated by the BCUC, but rather by the NEB. TM owns all of the outstanding shares of Terasen Pipelines (Jet Fuel) Inc. (TPJF). While the tolls of TPJF are regulated by the BCUC, TPJF is not a "public utility" as that term is defined in the *UCA* and the provisions of s. 54 of the *UCA* are not applicable to TPJF. KMI is a U.S. energy storage and transportation company. KMI operates, either for itself or on behalf of Kinder Morgan Energy Partners, L.P. (KMP), over 30,000 miles of natural gas and petroleum products pipelines.

scrutiny surrounding the application. The BCUC's Order is instructive to the gas industry, as it clearly stated its statutory mandate over the sale of public utilities and confirmed that it did not have the jurisdiction to address matters outside of its mandate, including: opposition to foreign ownership of resources; recent trade disputes with the U.S. government; and the U.S.'s general position on various environmental issues.

On 12 September 2005, the BCUC issued Order No. G-86-05 agreeing with KMI that an oral hearing was not necessary and establishing a written hearing process and a revised hearing timetable, leaving open the possibility of an oral phase of submissions if the BCUC Panel had any questions arising from the written submissions.[74]

Leading up to and after submitting its Application, Terasen and KMI conducted extensive consultations.[75] As part of Order No. G-76-05, KMI and Terasen were also ordered to hold public workshops to review the Application in the Greater Vancouver area, Whistler, Victoria, Nanaimo, Kelowna, Cranbrook, and Prince George.

Thirty-six parties registered as intervenors and over 8000 letters of comment were submitted by individual citizens, businesses, and other organizations. The BCUC Panel noted that virtually all of the letters of comment opposed the Transaction. A large number of letters expressed general anger over the Transaction, but offered no substantive reasons for their opposition. Some of these letters indicated a need for more information and time to consider the Transaction, and some also requested public hearings and/or a referendum on the sale. The vast majority of letters expressed concern over foreign ownership in general and American ownership in particular. Opposition to foreign ownership revolved around issues such as a perceived loss of control/sovereignty over resources (energy security), reduced quality of services, increased rates, job losses in British Columbia, recent trade disputes with the U.S. government, and the general position of the U.S. on various environmental issues.

Although the BCUC Panel appreciated the input of so many citizens and considered the strong public opposition towards this Transaction, the BCUC Panel noted that it was required to adjudicate the Application within its statutory mandate. The BCUC Panel noted that much of the opposition to this Transaction appeared to be based on misunderstandings about the existing ownership and structure of Terasen, the structure of the natural gas market in British Columbia, and the authority of the BCUC over public utilities operating in British Columbia.[76]

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74 After reviewing all written submissions, the BCUC advised that it did not have any questions arising from the written submissions, eliminating the need for an oral argument phase.

75 Such consultations included: direct contact with key stakeholders; advisories to all customers with information regarding the Transaction and advice as to how to access the information in regard to the Transaction via the TGI and KMI websites; and posting information, including responses to questions on issues in respect of the Transaction, on the TGI and KMI websites for access by customers and stakeholders.

76 For example, a significant number of letters of comment seemed to assume that Terasen is a Crown Corporation. Terasen is, in fact, broadly owned by private shareholders and, while there were some restrictions initially placed on the ownership of Terasen shares by foreigners following the amalgamation of private and public assets in the late 1980s, the Government of British Columbia removed these restrictions in 2003.

Finally, the BCUC Panel confirmed that this Application was not attempting to have the effect of altering the services or rates of the Terasen Utilities. KMI had made various assurances that it would not attempt to recover from ratepayers any costs associated with the Transaction, and that service levels would be maintained or enhanced. The BCUC Panel also noted that as the Transaction was subject to review under the *Investment Canada Act*,[77] the Transaction could not be completed until the federal government was satisfied that the investment was likely to be of net benefit to Canada and that the Transaction had to be approved by existing Terasen shareholders, two conditions beyond the scope of the BCUC Panel.[78]

2. *JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE V. BRITISH COLUMBIA (UTILITIES COMMISSION)*[79]

Pursuant to s. 101(1) of the *UCA*, an appeal lies from a decision or order of the BCUC to the British Columbia Court of Appeal when leave to appeal is first obtained from a judge of the Court of Appeal. Under s. 14(1) of the *Court of Appeal Act*,[80] a Notice of Appeal respecting a decision must be filed within 30 days of the decision being appealed.

In the past year, the only relevant appeal decided by the British Columbia Court of Appeal in respect of a BCUC order or decision was that brought by the Joint Industry Electricity Steering Committee. Although this appeal involves electricity rather than an oil or gas matter, it is relevant as it indicates that the Court of Appeal might be inclined to exercise its discretion to grant leave to appeal quite liberally.

This was a decision by the British Columbia Court of Appeal released on 13 June 2005. The Joint Industry Electricity Steering Committee, GSX Concerned Citizens Coalition, British Columbia Sustainable Energy Association, and Society Promoting Environmental Conservation (the Appellants) appealed from the decision of a chambers judge of the Court of Appeal,[81] refusing their application for leave to appeal an order of the BCUC that approved the Energy Purchase Agreement (EPA) entered into between British Columbia Hydro and Power Authority (BC Hydro) and the Duke Point Power Limited Partnership (DPP).

The Appellants had been intervenors in the hearing that led to the approval of the EPA. The Appellants sought leave to appeal on the basis that significant aspects of the approval process failed to accommodate the public interest requirements of s. 71 of the *UCA*[82] and failed to accord an appropriate level of procedural fairness. Their application for leave to

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[77] R.S.C. 1985, c. 28.

[78] On 18 October 2005, Terasen shareholders approved the Transaction with 95.6 percent of votes cast in favour. See *supra* note 72 at 12. On 16 November 2005, Investment Canada approved the Transaction. See "Kinder Morgan Receives Final Approval for Terasen Acquisition; Investment Canada Approves Deal" (16 November 2005), online: Kinder Morgan, Inc. <http://phx.corporate-ir.net/phoenix.zhtml?c=93621&p=irol-newsArticle&ID=783838&highlight=>.

[79] 2005 BCCA 330, 42 B.C.L.R. (4th) 245.

[80] R.S.B.C. 1996, c. 77.

[81] 2005 BCCA 233, 212 B.C.A.C. 48.

[82] *Supra* note 69.

appeal was dismissed. The Appellants appealed the decision on the basis that the chambers judge applied an overly stringent test for whether leave to appeal was warranted.

The Court of Appeal allowed the appeal on the basis that the chambers judge erred by assessing the merits of the proposed grounds of appeal, rather than whether the grounds raised substantial issues to be argued. Each ground of appeal proposed by the Appellants raised a substantial issue to be argued. Accordingly, the order of the chambers judge was set aside and the Appellants were granted leave to appeal.

D. EAST COAST BOARDS

1. CNLOPB DECISION 2005.02: AMENDMENT TO THE TERRA NOVA DEVELOPMENT PLAN

On 4 October 2005, the Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB)[83] approved Petro-Canada's North Graben exploitation scheme to develop the "NGSE" and "NGCE" fault blocks.[84] In its previous Decision 97.02, approving the Terra Nova Field Benefits and Development Plan, the CNLOPB noted that the potential of the North Graben area would be assessed early in the field life, and if commercial quantities of oil were confirmed in the area, the CNLOPB would require the proponent to submit a revision to its development plan. The CNLOPB has since concluded that it is possible that all of the fault blocks in the North Graben area could contain sufficient oil reserves to justify development. If all of the North Graben fault blocks are developed, as many as 16 development wells may be required to deplete the reserves.

With the approval of the exploitation scheme, the proponent is now in a position to develop the North Graben NGSE and NGCE fault blocks, using water injection for pressure support and existing facilities at the northwest and northeast drill centres. A producer-injector pair will be required in each fault block. The proponent must provide a delineation plan, acceptable to the CNLOPB, for the North Graben area by 30 September 2008.

2. CNSOPB, BEPCO. CANADA COMPANY — OFFSHORE EXPLORATION DRILLING PROGRAM ON THE SCOTIAN SLOPE OF NOVA SCOTIA

BEPCo. proposed to conduct an offshore exploration drilling program on the Scotian Slope of Nova Scotia, within exploration licence 2407 issued by the Canada-Nova Scotia

83 The CNLOPB is a federal-provincial agency responsible for the management of the offshore oil and gas industry in Newfoundland and Labrador under the mandate established by the mirror federal and provincial Atlantic Accord legislation, the *Canada-Newfoundland Atlantic Accord Implementation Act*, S.C. 1987, c. 3 and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*, R.S.N.L. 1990, c. C-2. The mandate of the CNLOPB includes: rights administration and resource estimation; operations and safety; environmental matters; and Canada-Newfoundland benefits. Access to CNLOPB decisions, guidelines, directives, and other releases to the industry can be obtained from the CNLOPB's website, online: <www.cnlopb.nl.ca>.

84 CNLOPB, Decision 2005.02: *Respecting the Amendment to the Terra Nova Development Plan* (August 2005).

Offshore Petroleum Board (CNSOPB).[85] The program entails the drilling of one to three wells during 2005-2007 and up to three appraisal wells during 2008-2009.

On 29 June 2005 the CNSOPB completed the comprehensive study of the BEPCo.'s Exploration Drilling Program and decided that it could exercise any power or perform any duty or function with respect to the project, as it was of the opinion that the project was not likely to cause significant adverse environmental effects.[86]

E. ONTARIO ENERGY BOARD

The Ontario Energy Board (OEB) is the regulator of Ontario's natural gas and electricity industries, operating as an adjudicative tribunal through public hearings that consider oral and/or written evidence. The OEB also provides advice on energy matters referred to it by the Minister of Energy and the Minister of Natural Resources. The OEB's mandate in respect of natural gas comes from the *Ontario Energy Board Act, 1998*.[87]

1. APPLICATIONS BY GREENFIELD ENERGY CENTRE LIMITED PARTNERSHIP AND UNION GAS LIMITED[88]

On 20 July 2005, Greenfield Energy Centre (GEC), a joint venture by Calpine and Mitsui, filed an application for leave to construct a natural gas pipeline to supply a 1005 megawatt (MW) gas-fired generating station in Courtright, south of Sarnia, under the operation of GEC. On 30 August 2005, Union Gas Limited (Union Gas) also filed an application for the same activity.

On 6 January 2006, the OEB indicated that it would approve both applications to construct a natural gas pipeline, but acknowledged that only one can proceed. It approved GEC's application, concluding the public interest would not be served if its application were denied. GEC could not currently access adequate services from Union Gas and, therefore, it was in the public interest to allow GEC to pursue those services directly through the option of physically bypassing the natural gas distribution grid in the franchise area of Union Gas.

GEC was granted permission to run a 16 inch line for approximately 2 km to connect its power generation plant directly to the international Vector Pipeline near Sarnia, Ontario. GEC was one of the successful bidders in Ontario's initiative to increase the amount of gas-

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85 The CNSOPB is the lead regulatory agency for all petroleum activities and resources in the Nova Scotia offshore area, pursuant to its mandate set out in the mirror legislation, the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*, S.C. 1988, c. 28, and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act*, S.N.S. 1987, c. 3. The mandate of the CNSOPB includes: rights administration and resource estimation; operations and safety; environmental matters; and Canada-Nova Scotia benefits. Access to CNSOPB decisions, guidelines, directives, and other releases to the industry can be obtained, online: CNSOPB <www.cnsopb.ns.ca>.

86 See the decision on the Canadian Environmental Assessment Registry (CEAR), Reference number 04-03-2712, *BEPCo. Canada Company – EL2407 Exploration Drilling Program* (29 June 2005), online: CEAR <www.ceaa.gc.ca/050/viewer_e.cfm?CEAR_ID=2712>.

87 S.O. 1998, c. 15, Sch. B.

88 OEB, Decision and Order, OEB File No. RP-2005-0022, EB-2005-0441, EB-2005-0442, EB-2005-0443, and EB-2005-0473 (6 January 2006), online: OEB <www.oeb.gov.on.ca/documents/cases/RP-2005-0022/decision_060106.pdf>.

fired power generation and eliminate coal as a fuel for electricity generation. Union Gas had proposed to supply the plant from its distribution facilities in the vicinity.

This is the first instance in which the OEB has permitted the physical bypass of a gas distribution utility. The OEB authorized both GEC and Union Gas to supply the plant, but the effect of authorizing GEC to do so is to give GEC the option of building its own direct connection to the Vector transmission system if it does not want service from Union Gas.

The effect of the decision was to allow GEC to obtain natural gas supplies for its plant, which is very close to the Vector pipeline, without paying any of the costs associated with Union Gas' distribution system. Union Gas and Enbridge (the other large Ontario gas distribution utility) have "postage stamp" rates, meaning that GEC will be the only gas user in an Ontario utility franchise area with, effectively, distance-based gas transmission costs.

During the hearing, the Industrial Gas Users Association (IGUA) stated that it did not take a position on whether bypass should be allowed for GEC or not, but that if it was allowed for GEC, then IGUA members would consider themselves entitled to the same direct access to gas transmission lines. However, the precedent effect of the GEC decision is not clear owing to the fact that in the same decision, the OEB referred the general issue of gas utility bypass to the ongoing Natural Gas Electricity Interface Forum.

2. GENERIC HEARING ON THE NATURAL GAS ELECTRICITY INTERFACE ISSUES AND STORAGE REGULATION

On 29 December 2005, the OEB commenced a proceeding on its own motion to determine: (i) whether it should order new rates for the provision of natural gas, transmission, distribution, and storage services to gas-fired generators (and other eligible customers); and (ii) whether to refrain, in whole or part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest.[89] The proceeding is commenced pursuant to ss. 19, 36, and 29, respectively, of the *Ontario Energy Board Act, 1998*.

The OEB has issued three Procedural Orders relating to hearing scope and the evidentiary process. The matter was heard by the OEB and Decision EB-2005-0551 was issued on 7 November 2006.[90]

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89 See OEB, Oral Decision, OEB File No. EB-2005-0551 (27 June 2006), online: OEB <www.oeb.gov.on.ca/documents/cases/EB-2005-0551/Decision_Orders/dec_oral_270606.pdf>. See also the OEB Order (30 June 2006), online: OEB <www.oeb.gov.on.ca/documents/cases/EB-2005-0551/Decision_Order/order_040706.pdf>.

90 See OEB, Oral Decision, OEB File No. EB-2005-0551 (7 November 2006), online: OEB <www.oeb.gov.on.ca/documents/cases/EB-2005-0551/Decision_Orders/dec_reasons_071106.pdf>.

III. LEGISLATIVE DEVELOPMENTS

A. FEDERAL

1. NATIONAL ENERGY BOARD DRAFT DAMAGE PREVENTION REGULATIONS

On 7 February 2005, the NEB announced it had completed the initial development phase of the draft Damage Prevention Regulations (DPR).[91] The DPR are intended to replace the *National Energy Board Pipeline Crossing Regulations*, Part I[92] and Part II.[93] The DPR have been submitted to the Department of Justice for review and analysis prior to pre-publication in the *Canada Gazette*, Part I and, at the date of writing, still have not been promulgated.

2. SECTIONS 82 TO 93 OF THE *PUBLIC SAFETY ACT, 2002* IN FORCE ON 20 APRIL 2005

On 20 April 2005, ss. 82 to 93 of the *Public Safety Act, 2002*[94] came into force. These sections contain specific amendments to the *NEB Act*[95] to provide the NEB with a clear legislative authority in respect of the security of pipelines and international power lines. The NEB can:

(a) order a pipeline company or certificate holder for an international power line to take measures to ensure the security of the pipeline or power line;

(b) make regulations respecting security matters;

(c) ensure the confidentiality of information relating to security in orders or proceedings;

(d) provide advice to the Minister of Natural Resources on security issues; and

(e) waive the publication requirement for applications to export electricity or to construct international power lines if there is a critical shortage caused by terrorist activity.

3. DRAFT GOAL-ORIENTED DRILLING AND PRODUCTION REGULATIONS

On 11 April 2005, the NEB sought comments on a draft Goal-Oriented Drilling and Production Regulations (D&PR),[96] an initiative the NEB undertook on behalf of Natural Resources Canada, the Province of Newfoundland and Labrador, the Province of Nova

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91 See draft DPR (October 2004), online: NEB <www.neb-one.gc.ca/ActsRegulations/NEBAct/DamagePreventionRegs/DamagePreventionRegsOctober2004_e.pdf>.
92 S.O.R./88-528.
93 S.O.R./88-529.
94 S.C. 2004, c. 15.
95 *Supra* note 2.
96 See draft Goal Oriented D&PR (April 2005), online: NEB <www.neb-one.gc.ca/ActsRegulations/cogoa/goalorienteddprdraftapril2005_e.pdf>.

Scotia, the CNLOPB, the CNSOPB, and the Department of Indian Affairs and Northern Development. The intent is to have the Goal-Oriented D&PR in force by approximately the end of 2006.

4. THE CANADA-FRANCE AGREEMENT ON TRANSBOUNDARY HYDROCARBON FIELDS

On 17 May 2005, Canada entered into an agreement with France to provide for an information exchange and management regime for hydrocarbon exploration and exploitation off the coasts of Newfoundland and Labrador, Nova Scotia, and the French islands of St. Pierre and Miquelon.[97] It also includes mechanisms for identifying a transboundary field, sharing resources and economic benefits between Canada and France, and allows for the negotiation of exploitation and unitization agreements for specific fields.

5. CHANGES TO THE *CANADIAN ENVIRONMENTAL PROTECTION ACT, 1999* TO IMPLEMENT THE *KYOTO PROTOCOL*

In the latter half of 2005, the federal government began implementing three key components of its Climate Change Plan, released on 13 April 2005: (1) the regulation of Large Final Emitters (LFEs); (2) the release of a background document on an Offset Credit System; and (3) the addition of greenhouse gases ("GHG") to Schedule 1 — List of Toxic Substances of the *Canadian Environmental Protection Act, 1999*.[98]

a. Proposed Large Final Emitters Regulation

The federal government intends to have the regulation in force before 1 January 2008, the beginning of the *Kyoto Protocol* commitment period. Consultations commenced in the fall of 2005 for interested participants to comment on:

- Equivalency and administrative agreements under the *CEPA 1999* to ensure national consistency of the mandatory emission intensity targets;

- Targets for existing facilities for the 2008-2012 period only (emissions caused by a fixed chemical reaction that cannot be reduced with existing technologies would receive a zero percent reduction target during that period whereas all other covered emissions would receive a 15 percent emission intensity reduction target);

- Best Available Technology Economically Available performance standards;

- Flexible compliance options (*e.g.*, credits from other LFEs, domestic offset credits, Technology Investment Units, and International Kyoto units);

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97 See "Canada and France to Work Together in Atlantic Waters" (17 May 2005), online: Department of Foreign Affairs and International Trade Canada <http://w01.international.gc.ca/minpub/Publication.aspx?isRedirect=True&Publication_id=382568&Language=E&docnumber=87>.

98 S.C. 1999, c. 33 [*CEPA 1999*].

- Price assurances to ensure the government keeps its commitment to cap the cost of compliance to $15/tonne for the 2008-2012 period;

- Rules applicable to mergers and acquisitions to determine which party carries the reporting obligation and compliance liability; and

- Penalties (not to exceed $200 per excess tonne of emissions).

b. Offset Credit System

On 11 August 2005, Environment Canada released its Overview Paper and Technical Background Document proposing a set of rules for the domestic Offset Credit System. The proposed Offset Credit System is intended to reward individuals, businesses, and organizations with offset credits when they implement projects that result in incremental GHG emission reductions or removals beyond what they would have done under normal business activities (*i.e.*, "business as usual" baseline). Potential offset projects include:

- Property developers who include renewable energy elements in their new subdivisions;

- Electricity or gas utilities that implement demand-side management programs that reduce energy consumption by their customers;

- Forestry companies that invest in reforestation; and

- Companies covered by the LFE regulations when they reduce emissions from activities that are not covered by the LFE regulatory requirements.

Companies, governments, organizations, or citizens undertaking such approved projects will be awarded credits that, in turn, may be sold to:

- Canadian companies in the LFE category to apply to their emission reduction targets;

- The Climate Fund, a new institution established by the 2005 Budget to purchase credits on behalf of the Government of Canada; or

- Another interested individual or organization.

The Technical Background Document describes in detail the necessary steps for the creation of an offset credit. In summary, there are four stages:

(a) Applying to register the GHG reduction or removal activity as an "offset project";

(b) Validating that the requirements for an offset project are met and completing the registration of the project;

(c) Verifying the emission reductions/removals that have been achieved by the project; and

(d) Issuing the corresponding number of offset credits.

To qualify for credits, the reductions or removals must meet several criteria, including:

- *Quantifiable*: The reductions or removals of GHG emissions from a registered offset project must be measurable using recognized protocols or methodologies;

- *Real*: An offset project must be a specific action that results in GHG emission reductions and removals (and does not result in emissions moving to another site);

- *Surplus*: Offset project reductions or removals will only be eligible to generate offset credits if such reductions or removals have not occurred as the result of a specified federal GHG regulation, program, or incentive;

- *Verifiable*: Qualified, accredited third parties must be able to verify that the reductions or removals have been achieved as claimed; and

- *Ownership*: There must be clear legal ownership of the GHG reductions or removals achieved from a project.

In late 2005, Environment Canada consulted with provinces, territories, industry, and Aboriginal groups, but at the date of writing, no plans have been announced to finalize or implement the Offset Credit System.

c. GHG Additions to List of Toxic Substances

On 30 November 2005, the federal government took the first step towards the development of the proposed LFE Regulation by adding the following GHGs to Schedule 1 – "List of Toxic Substances" of *CEPA 1999*,[99] on the basis that they "constitute or may constitute a danger to the environment on which life depends":[100] carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulphur hexafluoride. The purpose of this listing is to allow for the federal government to regulate these GHGs in order to implement its *Kyoto Protocol* plan.

However, the implications of this implementation are not fully understood by the Government of Canada or industry at this time and joint discussions continue. In particular, we note that it was the previous Liberal government that put forward the above three initiatives to implement the *Kyoto Protocol*. At the date of writing, the new Conservative-led minority government had not yet taken any firm position to implement the previous Liberal government's plan or to articulate its own *Kyoto Protocol* alternative. This uncertainty in the

[99] Order Adding Toxic Substances to Sch. 1 to the *Canadian Environmental Protection Act, 1999*, C. Gaz. 2005.I. 2870.

[100] *Supra* note 98, s. 64(b).

implementation of the *Kyoto Protocol* at the federal level may lead to a fragmented and regional approach undertaken by the provinces in implementing their own Kyoto compliance program or an alternative thereto.[101]

6. AMENDMENTS TO THE *MIGRATORY BIRDS CONVENTION ACT, 1994* — MINIMUM FINES FOR SPILLS FROM VESSELS

The *Migratory Birds Convention Act, 1994*[102] enacts an international agreement between Canada and the United States for the protection of migratory birds. Although most of the statute regulates harvesting or hunting, it also contains some environmental protection provisions. The *MBCA* prohibits the deposit of oil, oil waste, or other substances harmful to migratory birds in any waters or areas frequented by migratory birds, except as authorized by regulation.

The *Act to Amend the Migratory Birds Convention Act, 1994 and the Canadian Environmental Protection Act, 1999*[103] (Bill C-15) came into force on 28 June 2005. This amendment increases maximum penalties to up to $1 million and/or three years imprisonment and imposes minimum penalties for violations by vessels weighing 5000 tonnes or more, from $100,000 to $500,000, the first minimum fines in Canadian environmental law based on size of vessel rather than extent of harm.

7. AMENDMENTS TO THE *COMPREHENSIVE STUDY LIST REGULATIONS* UNDER THE *CANADIAN ENVIRONMENTAL ASSESSMENT ACT* RE: FIRST EXPLORATORY DRILLING PROJECTS

On 10 November 2005 the federal government changed the type of Environmental Assessments (EA) required for the initial exploratory drilling project in an offshore area from a comprehensive study to a screening. The change removed the term "exploratory drilling" and "section 15," which describes when an offshore drilling project is subject to a comprehensive study, from the existing *Comprehensive Study List Regulations*[104] under the *CEAA*.[105] Screenings tend to proceed in less time than comprehensive studies.

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[101] See, *e.g.*, Quebec's introduction of a carbon tax to pay for its implementation of the *Kyoto Protocol* (Rhéal Séguin, "Quebec unveils carbon tax" *The Globe and Mail* (16 June 2006) A1) and Alberta's *Emissions Trading Regulation*, *infra* note 111.

[102] S.C. 1994, c. 22 [*MBCA*].

[103] S.C. 2005, c. 23.

[104] S.O.R./94-638.

[105] *Supra* note 62.

B. ALBERTA

1. AMENDMENTS TO THE *OIL AND GAS REGULATION*, THE *PIPELINE REGULATION*, THE *NATURAL GAS ROYALTY REGULATION*, THE *DESIGNATION REGULATION* (*GAS UTILITIES ACT*), AND THE *NATURAL GAS PRICE PROTECTION REGULATION*

On 31 May 2005, the *Pipeline Regulation* was amended.[106] Changes to the *Regulation* reflect both changes in AEUB regulatory policy and processes and improvements in technology. Major goals of the revision were to continue to improve overall pipeline performance, as well as to address specifically the recommendations raised by the Public Safety and Sour Gas Committee in regard to sour gas pipeline safety. A secondary goal was to improve the organization and readability of the *Pipeline Regulation*. Because licensees may require an extended time to achieve compliance with new requirements in several sections, the revised *Pipeline Regulation* will come into force in stages.[107]

Other regulations amended include the *Oil and Gas Conservation Regulation*,[108] the *Natural Gas Royalty Regulation*,[109] the *Designation Regulation (Gas Utilities Act)*,[110] and the *Natural Gas Price Protection Regulation*.[111]

2. THE *EMISSIONS TRADING REGULATION*

On 22 February 2006, Alberta's Lieutenant Governor-in-Council approved the province's new *Emissions Trading Regulation*[112] under the Alberta *Environmental Protection and Enhancement Act*.[113] The *Regulation* authorizes the Minister of Environment to establish programs and other measures to support and enhance emissions trading and establishes the Emissions Trading Registry. It will be mandatory for operators of generating units with a

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106 *Pipeline Regulation*, Alta. Reg. 122/87 was repealed and replaced by *Pipeline Regulation*, Alta. Reg. 91/2005, further amended by the *Pipeline Amendment Regulation*, Alta. Reg. 186/2005, in force 15 October 2005.

107 The majority of the *Pipeline Regulation* came into force 31 May 2005. Requirements regarding signage, enhanced right-of-way surveillance on certain sour gas pipelines, inspection of surface construction activities on certain pipelines, and design using CSA component design pressures came into force after six months, on 30 November 2005. Requirements regarding improved operations and maintenance manuals, integrity management programs, annual right-of-way inspection, annual internal corrosion evaluation, registration with Alberta One-Call, ground disturbance training, discontinuing, or abandoning non-used pipeline, and remediation of stagnant ends where they are found during excavation work will come into force after 12 months, on 31 May 2006.

108 *Oil and Gas Conservation Amendment Regulation*, Alta. Reg. 184/2005, effective 20 September 2005.

109 *Natural Gas Royalty Regulation, 2002 Amendment Regulation*, Alta. Reg. 139/2005, in force 14 July 2005.

110 Repealed and replaced by *Designation Regulation*, *supra* note 55. Added to the designation list (and therefore now subject to ss. 26 and 27 of the *GUA*, *supra* note 42) are the owners of AltaGas Utilities Inc., AltaGas Utility Holdings Inc., ATCO Gas and Pipelines Ltd., Canadian Utilities Limited, and CU Inc. Sections 26 and 27 identify transactions by designated owners of public utilities that require prior approval of the AEUB.

111 *Natural Gas Price Protection Regulation*, Alta. Reg. 157/2001 has been amended by *Natural Gas Price Protection Amendment Regulation*, Alta. Reg. 238/2005. In particular, s. 1 regarding interpretation of the *Regulation* has been amended. Also, ss. 2(1.1)-(1.2) regarding the determination of the price of marketable gas in Alberta have been added.

112 Alta. Reg. 33/2006.

113 R.S.A. 2000, c. E-12.

maximum continuous rating of 25 megawatts or more to establish an emissions trading account by designated deadlines. As described above under the federal section "Changes to *CEPA 1999* to implement the *Kyoto Protocol*," the lack of certainty with respect to the implementation of the *Kyoto Protocol* at the federal level has led to some concerns regarding Alberta's unilateral plans to move ahead with regulated GHG emission intensity targets for industry, without knowing what policies the new federal government will adopt.[114]

3. *BASELINE WATER-WELL TESTING FOR COAL BED METHANE OPERATIONS* STANDARD

On 6 April 2006, Alberta Environment, in collaboration with the AEUB, issued the *Standard for Baseline Water-Well Testing for Coalbed Methane Natural Gas Operations*.[115] This standard requires that, effective 1 May 2006, operators wishing to develop shallow coalbed methane must first offer to test rural Albertans' active water wells within a minimum 600 m radius of new or recompleted coalbed methane wells (with perforations above the base of groundwater protection). If there are no wells within 600 m, operators must offer to provide testing for at least one well within an 800 m radius.

The required testing, intended to measure and track any possible side effects of coalbed methane activity, must provide baseline data on each water well's production capacity, water quality (including bacteria), and the absence or presence of gas in the water well (including methane gas). Once complete, the test results must be submitted to Alberta Environment and the landowner.

Although most coalbed methane companies already voluntarily test water wells, concerns were highlighted during public consultation about the need to collect pre-drilling, baseline data to aid in establishing a correlation between coalbed methane drilling and local water wells going dry or producing black water. Alberta Environment has stated that the baseline testing results are intended to assist in an investigation should complaints occur.

C. BRITISH COLUMBIA

1. AMENDMENTS TO THE *WASTE DISCHARGE REGULATION* TO ENABLE THE *CODE OF PRACTICE FOR THE DISCHARGE OF PRODUCED WATER FROM COAL BED GAS OPERATIONS*

By Ministerial Order No. 74 in April 2005, the Minister of Water Land and Air Protection (now the Minister of Environment) established a *Code of Practice for the Discharge of Produced Water from Coal Bed Gas Operations*.[116] This is added to the table in Schedule 2 of the *Waste Discharge Regulation*.[117] The effect of registering this *Code* under the *Environmental Management Act*[118] is to allow for industries that have discharged or produced

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114 See CAPP, "CAPP concerned about timing of Alberta's movement on GHG targets" (6 June 2006).

115 (April 2006), online: Water For Life, Alberta Government <www.waterforlife.gov.ab.ca/coal/docs/CBM_Standard.pdf>

116 B.C. Reg. 156/2005.

117 B.C. Reg. 320/2004.

118 S.B.C. 2003, c. 53 [*EMA*].

water from coalbed gas operations to elect to operate under a *Code of Practice* rather than having a permit. This is the first *Code of Practice* to have been registered under the *EMA*.

IV. BOARD AND AGENCY POLICY DEVELOPMENTS

A. FEDERAL

Over the past year, the NEB published the following Requirements and Agreement.

1. NEW REQUIREMENTS FOR OPERATIONS AND MAINTENANCE ACTIVITIES ON PIPELINES REGULATED UNDER THE *NEB ACT*

On 14 July 2005, the NEB released its Operations and Maintenance Activities on Pipelines regulated under the *NEB Act*:[119] Requirements and Guidance Notes (Operations Requirements).[120] The Operations Requirements allow companies to carry out operations and maintenance activities without having to submit an application under s. 58 of the *NEB Act*, which would normally trigger the environmental assessment process under the *CEAA* enabling *Law List Regulations*.[121] The NEB will continue to regulate operations and maintenance activities through its inspection and audit programs to ensure they are carried out with respect to safety, security, environmental protection, economic efficiency, and the rights of those affected.

The Operations Requirements are intended to provide operators and the public with greater clarity about the NEB's expectations for the management and regulation of operations and maintenance activities on NEB-regulated facilities. The Operations Requirements have significantly streamlined the review process that pipeline companies are required to undergo, as they eliminate both the s. 58 application and the *CEAA* environmental assessment process for carrying out relatively routine operations and maintenance activities. Their development support the federal government's Smart Regulation initiative, which promotes the use of appropriate regulatory instruments while streamlining processes and removing unnecessary steps and information requirements.[122]

2. MEMORANDUM OF UNDERSTANDING BETWEEN THE NEB AND THE U.S. PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

On 1 November 2005, the NEB signed a Memorandum of Understanding (MOU) with the U.S. Pipeline and Hazardous Materials Safety Administration.[123] The MOU provides the

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119 *Supra* note 2.

120 See NEB, *Operations and Maintenance Activities on Pipelines Regulated under the* National Energy Board Act*: Requirements and Guidance Notes* (7 July 2005), online: NEB <www.neb-one.gc.ca/ActsRegulations/NEBAct/GuidanceNotes/OperationsMaintenancePipelines_e.htm> [Operations Requirements].

121 S.O.R./94-636.

122 See the Government of Canada's Smart Regulation initiative, online: Government of Canada <www.psmod-modfp.gc.ca/initiatives/sr-ri_e.asp>.

123 *Memorandum of Understanding between the National Energy Board and the Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation* (1 November 2005), online: NEB <www.neb-one.gc.ca/ActsRegulations/MOUs/neb_phmsa_usdot_2005_11_01_e.pdf>.

framework for increased compliance data sharing, monitoring and assessment activities, staff exchanges, and joint training opportunities in order to encourage more consistent application of the regulation of pipelines crossing the Canada-U.S. border. The MOU is to be revisited annually.

This MOU is part of the Security and Prosperity Partnership for North America, a trilateral agenda inaugurated on 23 March 2005 by Canada, the United States, and Mexico to increase the security, prosperity, and quality of life in North America.[124]

B. ALBERTA

1. PROPOSED CHANGES TO THE *OIL AND GAS CONSERVATION REGULATIONS* AND THE *PIPELINE REGULATION* RESPECTING THE ABANDONMENT OF WELLS, FACILITIES, AND PIPELINES

On 13 April 2004, the AEUB issued Bulletin 2004-09: Consultation Regarding Proposed Amendments of Regulations on the Abandonment of Wells, Facilities, and Pipelines, outlining the policy for amendments to the *Oil and Gas Conservation Regulations*[125] and the *Pipeline Regulation*[126] and prescribing circumstances under which the AEUB may order wells, pipelines, and facilities to be abandoned.

In May 2005, the AEUB drafted a number of "housekeeping" amendments with respect to the policy outlined in Bulletin 2004-09. For example, for the *Oil and Gas Conservation Regulations* and *Pipeline Regulation*, amendments consist of adding a definition of "resident"; adding that a licensee is also responsible for abandoning a facility or pipeline; and adding a provision for cases where the licensee is not or ceases to be an Alberta resident and has not appointed an agent, has no working interest in participation in the well or facility or pipeline, *etc.*

2. DIRECTIVE 019: *AEUB COMPLIANCE ASSURANCE — ENFORCEMENT*[127]

On 27 July 2005, the AEUB modified the compliance framework for the oil and gas industry with the issuance of Directive 019, which includes new processes designed to protect public safety, minimize environmental impacts, preserve equality, and ensure conservation of resources. The Directive updates a series of AEUB Enforcement Ladders, which were unveiled in 1999 and set out the rules for enforcement when a licensee was not complying with AEUB requirements.

Enforcement actions may include non-compliance fees, self-audits or inspections, increased audits or inspections, third-party audits or inspections, partial or full suspensions, or suspensions and cancellation of permits, licences, or approvals. Directive 019 also

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124 See details on the Security and Prosperity Partnership of North America Agenda, online: <www.spp.gov>.

125 Alta. Reg. 151/71.

126 *Supra* note 106.

127 (20 February 2007), online: AEUB <www.eub.ca/docs/documents/directives/Directive019.pdf> [Directive 019].

provides for manual escalation of enforcement actions for persistent non-compliance, enforcement actions based on a pre-determined risk assessment, and improved access to compliance information. Escalation will now include the AEUB deploying a senior employee to assess the situation and connect with the company to convey directly the gravity of continued non-compliance, rather than the AEUB just automatically escalating enforcement measures by issuing a letter.

Effective 1 January 2006, Directive 019 replaced Informational Letter 99-4: *AEUB Enforcement Process, Generic Enforcement Ladder and Field Surveillance Enforcement Ladder*. Directive 019 supersedes the Enforcement Ladders of all other AEUB directives and guides. Enforcement actions begun under Informational Letter 99-4 and for which compliance had not been achieved by 31 December 2005 will continue under Directive 019.

3. AEUB GUIDE 66: *PIPELINE INSPECTION MANUAL* (NOVEMBER 2001)

Guide 66 is undergoing a revision to incorporate the contents of the revised *Pipeline Regulation* and is to be reissued as Directive 066.[128] Until Directive 066 becomes available, inspection and enforcement will continue using the existing Guide 66. While the majority of the *Regulation* became effective 31 May 2005, AEUB Field Surveillance staff will not be enforcing any of the new requirements until the revised inspection manual is published.

4. AEUB GUIDE 56: *ENERGY DEVELOPMENT APPLICATIONS AND SCHEDULES*

Guide 56 is also being revised. The next edition, to be issued as Directive 056,[129] will incorporate the changes contained in the amended *Pipeline Regulation* in regard to application processes. Until Directive 056 is published, application processes in the existing Guide 56 are to be used.

5. MINEABLE OIL SANDS STRATEGY

In October 2005, the Alberta Government released its Mineable Oil Sands Strategy (MOSS).[130] The MOSS addresses oil sands mine development and environmental management, under the direct responsibility of three ministries: Energy, Environment, and Sustainable Resource Development. It will also have implications for other ministries with direct responsibility for socio-economic development, infrastructure, and Aboriginal people.

The MOSS is intended to supersede the "Fort McMurray-Athabasca Oil Sands Subregional Integrated Resource Plan" for the mineable oil sands area, to ensure that the mineable oil sands area will be managed as a coordinated development zone, thus shifting from current project level management to zonal level management for mineable oil sands.

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[128] *Requirements and Procedures for Pipelines* (December 2005), online: AEUB <www.eub.ca/docs/documents/directives/Directive066.pdf> [Directive 066].

[129] *Energy Development Applications and Schedules* (12 September 2005), online: AEUB <www.eub.ca/docs/documents/directives/directive056.pdf> [Directive 056].

[130] See online: Alberta Department of Energy <www.energy.gov.ab.ca/docs/oilsands/pdfs/MOSS_Policy 2005.pdf>.

In January 2006, the Alberta Government established the Oil Sands Consultation Group, mandated to provide revised plans for a consultation process for oil sands development. The Oil Sands Consultation Group delivered a final report to the Government on 31 March 2006, making nine recommendations.[131] The key recommendations are:

- a hybrid multi-stakeholder and panel model and process should be developed and used;
- the scope of the consultation should include economic, environmental, and social issues considered in an integrated manner;
- consultation on oil sands development should be undertaken as a subject matter, not on a defined geographic area;
- the consultation process should include assessment of possible linkages to other policies or processes already in place, government or otherwise;
- the consultation process should be structured so as not to prejudice the consultation rights of First Nations;
- consultation should take place in the three oil sands areas: Peace River, Cold Lake, and Athabasca, as well as Edmonton and Calgary; and
- the entire consultation process should be completed by June 2007.

On 17 May 2006, the Alberta Government announced that it accepted all nine recommendations made by the Oil Sands Consultation Group.[132] In particular, it committed to establishing a multi-stakeholder committee accountable for the overall consultation process, and a panel to collect public input. The panel will hold public meetings and information sessions, especially in the main oil sands areas of Fort McMurray-Wood Buffalo, Peace River, Athabasca, and Cold Lake.

Members of both the committee and the panel will be appointed by government to ensure representation from the public, industry, environmental groups, First Nations, and other stakeholders. Public consultations are expected to start in September 2006, with the process to be completed by June 2007.

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131 See Oil Sands Consultation Group, *Final Report and Recommendations* (31 March 2006), online: Alberta Environment <www.environment.gov.ab.ca/info/library/7645.pdf>.

132 See "Government commits to comprehensive process for oil sands consultation" (17 May 2006), online: Government of Alberta <www.gov.ab.ca/acn/200605/1991344128C60-00EA-99FB-276D6D1AD3FC8EB3.html>.

6. DIRECTIVE 033: *WELL SERVICING AND COMPLETIONS OPERATIONS — INTERIM REQUIREMENT REGARDING THE POTENTIAL FOR EXPLOSIVE MIXTURES AND IGNITION IN WELLS*[133]

On 6 February 2006, the AEUB issued Directive 033, requiring licensees to have documented practices available at the well site for the safe management of the potential for explosive mixtures and ignition in wells and associated surface equipment, and to ensure that all well site staff responsible for well control and blowout prevention understand these practices and know how to apply them. This interim requirement expands upon existing AEUB requirements for well control, blowout prevention, and crew training procedures to include an additional new requirement for addressing the potential for explosive mixtures and ignition in wells.

7. BULLETIN 2006-11: *WATER RECYCLE, REPORTING, AND BALANCING INFORMATION FOR IN SITU THERMAL SCHEMES*[134] AND BULLETIN 2006-12: *VOLUNTARY SURVEY OF INDUSTRY ABANDONMENT AND RECLAMATION COSTS*[135]

The AEUB issued Bulletin 2006-11 on 28 March 2006 to provide detailed information on reporting of water volumes to the Petroleum Registry of Alberta, calculation of water recycle, and determination of a facility water balance. The AEUB was to issue a draft directive later in 2006 to provide details on its requirements for water balance and water recycle calculations for in situ thermal schemes, along with requirements for reporting and measurement accuracy of all significant water streams within a thermal scheme. The draft directive will also require produced water recycle for thermal schemes using water volumes in excess of 500,000 m^3 per year, regardless of water quality.

The AEUB issued Bulletin 2006-12 on 28 March 2006, requesting licensees to participate in a voluntary industry survey of the costs to abandon and reclaim conventional oil and gas wells and facilities in Alberta. The information obtained through this survey is to be considered in updating of the regional abandonment and reclamation cost parameters used by the Licensee Liability Rating Program.

To help ensure that a sufficient data set is collected, each licensee that abandoned a well or facility in Alberta during the 2005 calendar year is requested to participate in this voluntary industry survey. Additionally, each licensee that either obtained a Reclamation Certificate during the 2005 calendar year or is prepared to provide a cost estimate for a near-certified site (no remaining earthwork) for a well or facility in Alberta is also encouraged to participate. The closing date for submission of abandonment and reclamation cost information was 2 June 2006.

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133 (6 February 2006), online: AEUB <www.eub.ca/docs/documents/directives/Directive033.pdf> [Directive 033].

134 (28 March 2006), online: AEUB <www.eub.ca/docs/documents/bulletins/Bulletin-2006-11.pdf> [Bulletin 2006-11].

135 (28 March 2006), online: AEUB <www.eub.ca/docs/documents/bulletins/Bulletin-2006-12.pdf> [Bulletin 2006-12].

C. BRITISH COLUMBIA

1. OIL AND GAS COMMISSION (OGC) EASES COMMINGLING RULES IN THE DEEP BASIN

On 16 January 2006, the OGC announced it had issued an Interim Approval on 28 December 2005,[136] under the authority of s. 41 of the *Drilling and Production Regulation*,[137] allowing commingled production of specified sweet gas bearing formations within specified zones in the "Deep Basin" of northeastern British Columbia.[138] The specified zones include the Paddy, Cadotte, Notikewin, Falher, Bluesky, Gething, Cadomin, and Nikinassin zones, most of which are characterized as either extensive, low permeability sands, or containing pools of limited size and modest profitability.

As a result, operators of commingled production in the specified zones of the Deep Basin are no longer required to obtain prior regulatory approval for commingling production from the specified sweet natural gas bearing formations, but are only responsible to notify and report when undertaking commingled productions within the specified zones.[139] Previous OGC commingled production approvals have been issued only on the basis of individual wells, or two specific pools, following an application.

Commingled production is expected to maximize production and resource recovery from the specified zones. Further details on the Interim Approval are found in the associated Interim Guide,[140] specifying the criteria by which an operator may commingle production from two or more zones in a well. Commingling is not allowed if the reservoir pressure of any zone exceeds 90 percent of the fracture zone of any other zone proposed for commingling. Excessive water production from a commingled zone, although left to the operator's discretion, requires intervention if produced in amounts that may negatively impact ultimate recovery from other commingled zones. It is recognized that commingled production may enhance gas recovery via increased lifting capacity from zones with high liquid production.

The Interim Approval applies to both new wells and the re-completion of existing well bores. Individual well commingling applications can still be made for zones that do not meet

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136 See OGC, "Commingled Production — Interim Approval, Deep Basin Area" (28 December 2005), online: OGC <www.ogc.gov.bc.ca/documents/forms/reservoir/Area%20Commingle%20Order%20-%20Interim.doc>.

137 B.C. Reg. 362/98.

138 See OGC, "Commingled Production Area Approval — Deep Basin," Information Letter #OGC 06-01 (16 January 2006), online: OCG <www.ogc.gov.bc.ca/documents/informationletters/OGC%2006-01%20Commingled%20Production%20Area%20Approval%20-%20Deep%20Basin.pdf>.

139 The regulatory requirements include: submission of a "Notice of Commencement or Suspension of Operations" (BC-11 Forms) for each commingled zone in a wellbore; reporting gas, water, and condensate production from a commingled well (Ministry of Small Business and Revenue BC S-1 and BC S-2 Forms) to the deepest active well event of the commingled group of zones in the wellbore; and submission of a notification for each commingled well, within 30 days of final completion operations.

140 See OGC, "Commingled Production — Interim Approval," OGC-05362 (28 December 2005), online: OGC <www.ogc.gov.bc.ca/documents/forms/reservoir/Area%20Commingle%20Order%20-%20 Interim.doc>.

the criteria set out in the Interim Guide. Final approvals are expected in Spring 2006 to replace the Interim Approval measures, to allow for full implementation.

2. OGC PIPELINES AND FACILITIES OPERATIONS MANUAL (OCTOBER 2005)

The British Columbia OGC released its Pipelines and Facilities Manual for October 2005.[141] The OGC is phasing in a "performance-based" approach to managing oil and gas industry development in British Columbia. During this first phase, the OGC will introduce a new approach to regulate pipeline design and construction. OGC efforts will shift from reviewing preliminary surface and technical information at the front end of the planning process to assessing the performance of companies' activities against clear standards.

This document identifies the framework for the OGC's regulation of pipeline planning, construction, and operation, from the right to occupy Crown land and related tenures, through the Notice of Construction Start, Leave to Open, issuance of Certificate of Operations, and the Licence of Occupation, to the conclusion of a Statutory Right of Way. Within this framework, the OGC provides guidance that oil and gas companies should follow in order to obtain authorizations for surface access and construction of pipelines on Crown and private land. It also guides the OGC to achieve a consistent and obvious approach when reviewing applications and carrying out compliance and enforcement activities.

The goal of the OGC is to issue an authorization within 15 to 20 working days of receipt of a completed routine application. For routine applications, the OGC's role will normally be limited to the following:

(a) Complete First Nations consultations, where required;

(b) Complete status checks for private and Crown land to identify potential surface ownership and tenure conflicts; and

(c) Make decisions regarding the issuance of surface authorizations, including temporary permits to occupy Crown land under the *Land Act*,[142] cutting permits under the *Forest Act*,[143] and permission for changes in or about a stream under the *Water Act*.[144]

3. OIL AND GAS REGULATORY IMPROVEMENT INITIATIVE DISCUSSION PAPER

In this Discussion Paper,[145] dated 1 December 2005, the Ministry of Energy, Mines and Petroleum Resources proposes, among other regulatory changes, to enact a new

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141 The most recent version, released January 2007 can be found online: OGC <www.ogc.gov.bc.ca/formschecklists.asp?view=11>.

142 R.S.B.C. 1996, c. 245.

143 R.S.B.C. 1996, c. 157.

144 R.S.B.C. 1996, c. 483.

145 See Oil and Gas Regulatory Improvement Initiative, Discussion Paper (1 December 2005), online: Ministry of Energy, Mines & Petroleum Resources <www.em.gov.bc.ca/Oil&gas/reg_discussion_paper.pdf>.

comprehensive statute that would consolidate the OGC jurisdiction currently provided under the *Pipeline Act*,[146] *Oil and Gas Commission Act*,[147] and *Petroleum and Natural Gas Act*,[148] and incorporate upstream permitting, compliance, and enforcement for oil and gas activities in the *Forest Act*, *Forest Practices Code of British Columbia Act*,[149] *Heritage Conservation Act*,[150] *Land Act*, *EMA*,[151] and *Water Act*. The deadline for comment was 24 February 2006.

4. ORPHAN FUND TAX

On 3 February 2006, the OGC announced a new "orphan site tax" to establish a province-wide Reclamation Fund, to take effect on 1 April 2006.[152] The purposes of the Orphan Fund are: to pay the costs of abandonment and restoration of orphan wells, test holes, production facilities, and pipelines (under the *Petroleum and Natural Gas Act* or the *Pipeline Act*); to pay costs incurred in pursuing reimbursement for the costs referred to above from the person responsible for paying them; to pay any other costs directly related to the operations of the OGC in respect of the fund; and to pay compensation to land owners on whose land the OGC expends money on an orphan site if, on application by a land owner, the OGC is satisfied that the operator has failed to make payments due to the land owner under a surface lease, and subject to the maximums, conditions, and limitations prescribed by regulation.

5. AMENDMENT TO PUBLIC INVOLVEMENT GUIDELINE

Effective 1 April 2006, the OGC's Public Involvement Guideline is amended to increase the personal consultation radius for well sites, flaring, and facilities. Prior to submitting an activity application to the OGC, companies must undertake consultation with the public (including landowners, occupants, affected parties, and all residents).[153] The OGC's Public Involvement Guideline provides guidance for industry to involve the public in activities that may affect them. The personal consultation radius for a proposed well site and flaring activity will be increased from 0.5 km to 1.0 km. The personal consultation radius for a proposed sweet facility will be 1.0 km rather than the previous 0.5 km, and consultation for a sour facility will be increased from 1.5 km to 3.0 km.

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146 R.S.B.C. 1996, c. 364.

147 S.B.C. 1998, c. 39.

148 R.S.B.C. 1996, c. 361.

149 R.S.B.C. 1996, c. 159.

150 R.S.B.C. 1996, c. 187.

151 *Supra* note 118.

152 See OGC, "Tax for Orphan Site Reclamation Fund," Information Letter #OGC 06-03 (3 February 2006), online: OGC <www.ogc.gov.bc.ca/documents/informationletters/OGC%2006-03%20Orphan%20Fund%20Tax.pdf>.

153 See OGC, "Amendment to the Public Involvement Guideline," Information Letter #OGC 06-05 (24 March 2006), online: OGC <www.ogc.gov.bc.ca/documents/informationletters/OGC%2006-05%20Amending%20Public%20Involvement%20Guideline.pdf>.

D. EAST COAST

1. DRAFT STRATEGIC ENVIRONMENTAL ASSESSMENT FOR PETROLEUM ACTIVITIES IN GULF OF ST. LAWRENCE OFFSHORE WESTERN NEWFOUNDLAND

In May 2005, the CNLOPB released documents outlining the proposed scope of strategic environmental assessments (SEAs) for petroleum exploration activities in the Gulf of St. Lawrence offshore western Newfoundland. The SEAs are designed to: evaluate potential environmental effects associated with offshore oil and gas exploration activities; recommend general mitigative measures; and identify any required monitoring measures.[154]

2. DRAFT STRATEGIC ENVIRONMENTAL ASSESSMENT FOR PETROLEUM ACTIVITIES IN MISAINE BANK AREA OFFSHORE CAPE BRETON

The CNSOPB released, on 4 July 2005, the *Strategic Environmental Assessment of the Misaine Bank Area*[155] — a draft assessment report that is intended to provide

> an overview of the existing environment in the Misaine Bank area [offshore Cape Breton] ... [and the] environmental effects associated with offshore exploration activities, [identify] knowledge and data gaps, [highlight] issues of concern, and [make] recommendations for mitigation and planning in the area. Information from the SEA will assist the CNSOPB in determining whether exploration rights should be offered in whole or in part for the Misaine Bank, and may also help to identify appropriate general restrictive or mitigative measures applicable to exploration activities.[156]

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154 Environmental Research Associates, "Western Newfoundland and Labrador Offshore Area, Strategic Environmental Assessment" (December 2005), online: CNLOPB <www.cnlopb.nl.ca/env/sea/wnsearpt.pdf>.

155 Online: CNSOPB <www.cnsopb.ns.ca/whatsnew/pdf/MisaineSEA_CNSOPB_REV_2.pdf>. The final SEA report was released December 2005, online: CNSOPB <www.cnsopb.ns.ca/environment/pdf/misaineseafinalrep.pdf>.

156 "CNSOPB releases Draft Strategic Environmental Assessment" (5 July 2005), online: CNSOPB <www.cnsopb.ns.ca/whatsnew/news_Jul-05-5.html>.