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

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This article identifies and outlines significant regulatory decisions, legislative changes and regulatory policy developments occurring from April 2003 through March 2004 that primarily affect the midstream and upstream oil and gas industry in Canada. It begins by reviewing major National Energy Board (NEB) decisions, including pipeline and powerline applications and recent toll and tariff rulings. The NEB portion of the article outlines important procedural issues, such as Appropriate Dispute Resolution, a new Filing Manual and pre-application meetings with staff members. The article emphasizes the significant impact that NEB decisions have on the Canadian energy industry. The authors also highlight applications in environmentally sensitive or urban areas, special well spacing requests and joint review panel decisions concerning oil sands projects. Directives and guidelines from Alberta Energy and Utilities Board concerning the gas over bitumen issue are mentioned. In addition, the authors examine a series of legislative developments that will impact the industry, including amendments to various statutes and regulations by the Canadian, Alberta and British Columbia governments.

Cet article détermine et énonce les décisions réglementaires, les changements législatifs et les développements de politiques réglementaires importants qui se sont produits d'avril 2003 à mars 2004 touchant essentiellement les activités médianes et en amont du secteur pétrolier et gazier au Canada. Les auteurs commencent par revoir les décisions de l'Office national de l'énergie (ONE), incluant les demandes de pipelines et de lignes sous tension ainsi que les dernières décisions relatives aux droits et tarifs. La portion de l'article sur l'ONE décrit les grandes questions de procédure, comme les mécanismes appropriés de règlement de différends, un nouveau Guide de dépôt et des réunions avec les membres du personnel préalables à la demande. L'article souligne l'importance des décisions de l'ONE pour le secteur énergétique du Canada. Les auteurs mettent en évidence aussi les demandes en zones urbaines et en zones délicates sur le plan environnemental, des demandes spéciales d'espacement des puits et une commission mixte d'évaluation des décisions relatives aux projets des sables bitumineux. Des directives et lignes directrices du Alberta Energy and Utilities Board sur la question du gaz sur le bitume y sont mentionnées. De plus, les auteurs examinent les développements législatifs ayant une incidence sur ce secteur, incluant les amendements à diverses lois et règlements apportés par les gouvernements du Canada, de l'Alberta et de la Colombie-Britannique.

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I. INTRODUCTION

This article identifies and outlines significant regulatory decisions, legislative changes and regulatory policy developments occurring from April 2003 through March 2004 that primarily affect the upstream and midstream oil and gas industry in Canada. Both provincial and federal items are discussed, including decisions, orders and policies emanating from the National Energy Board (NEB) and the Alberta Energy and Utilities Board (AEUB).

An exhaustive report on all regulatory developments, legislative changes and regulatory policy changes since April 2003 has not been provided and the focus of this article is on developments to the regulatory landscape, that in the authors' opinion, are significant to the oil and gas industry.[1]

II. REGULATORY DECISIONS

A. NATIONAL ENERGY BOARD DECISIONS

While few in number, the NEB decisions that have been issued over the last year illustrate that there are still significant matters that continue to be addressed by the NEB. An increased emphasis on the public interest, environmental matters and Aboriginal consultation in connection with new facilities is also reflected in these decisions.

1. RH-1-2002: TRANSCANADA PIPELINES LIMITED 2003 TOLLS AND TARIFF[2]

a. Background of Hearing

TransCanada PipeLines Limited (TCPL) applied to the NEB for approval of its tolls for the 2003 calendar year and in respect of certain other tariff matters. This hearing was significant as it represented the first fully contested cost-of-service tolls hearing for TCPL since the 1994 test year. Since that time, TCPL's tolls have been established on the basis of NEB-approved negotiated settlements between TCPL and its shippers with the notable exception of cost of capital matters for the 2001 and 2002 test years. These matters were the subject of the RH-4-2001 proceeding.[3] The RH-1-2002 hearing, which required 34 hearing days, was the sole public hearing held by the NEB during the past year to consider tolling matters, although tolling matters with respect to other NEB regulated pipelines were approved as a result of uncontested applications relating to toll settlements.

b. Rate Base and Revenue Requirement

TCPL proposed an average rate base for the 2003 test year of $8.57 billion and a net revenue requirement of $1.967 billion. TCPL's proposed rates would increase the Eastern

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[1] The views expressed in this article are those of the authors and do not represent the position of any client of Macleod Dixon LLP.

[2] *Reasons for Decision In the Matter of TransCanada PipeLines Limited, 2003 Tolls and Tariff Application* (July 2003), RH-1-2002 (NEB) [RH-1-2002].

[3] *Reasons for Decision In the Matter of TransCanada PipeLines Limited, Fair Return Application dated June 2001, In respect of Cost of Capital matters* (June 2002), RH-4-2001 (NEB) [RH-4-2001].

Zone toll for 2003 by approximately 7 percent to $1.232/GJ. The NEB approved TCPL's applied for rate base, but reduced its applied for net revenue requirement.

c. Financial Accounting

Several of the intervenors in this proceeding complained that TCPL was not maintaining its financial accounts in a manner which facilitated a line-by-line analysis of all pipeline cost items, and such analysis was required in order to ensure that TCPL's tolls were just and reasonable. While the NEB determined that it had satisfactory information to determine TCPL's tolls for 2003, it directed TCPL to provide more detailed information in the future.

d. Operations, Maintenance and Administration Costs

TCPL's applied-for Operations, Maintenance and Administration Costs were $246.2 million, an increase of $36.3 million or 17.3 percent over the 2002 amount. The NEB reduced the applied-for amount by approximately $13.5 million as the NEB did not accept TCPL's justification to support an increase of 23 employees for 2003. It reduced the amount of long-term incentive compensation expense that was required to be borne by shippers, and it disallowed the costs associated with TCPL's conversion of its pension plan to a defined benefits plan.

e. Depreciation

Depreciation is a major cost item in any pipeline's cost-of-service and was a major issue in the RH-1-2002 proceeding. TCPL applied for an increase in its composite depreciation rate from 2.89 percent for 2002 to 3.65 percent for 2003, which would have resulted in an increase in TCPL's cost-of-service amounting to $88.3 million, plus an additional $51 million in income tax expense. This would equate to an approximate increase in the 2002 Eastern Zone toll of $0.086/GJ. TCPL's last full depreciation study that had been approved by the NEB was in 1992.

TCPL justified its requested increase in depreciation rate based on a new depreciation study that incorporated a number of changes. TCPL also proposed to change its depreciation method from average service life to equal life group. The NEB rejected the change in depreciation method but essentially approved all other significant aspects of TCPL's depreciation study. The approved comprehensive depreciation rate for 2003 was approximately 3.42 percent.

In approving the higher depreciation rate, the NEB accepted TCPL's position that an appropriate economic planning horizon for its pipeline should be reduced to 25 years. TCPL had suggested using a reduced planning horizon given that the retirement of facilities on its mainline pipeline would arise not only as a result of wear and tear and deterioration, but also as a result of economic forces such as a significant decline of gas supply from the Western Canada Sedimentary Basin, resulting in a lower utilization of TCPL's pipeline. Other intervenors had proposed a 30 or 35-year economic planning horizon.

f. Incentive Programs

TCPL had proposed that two of the incentive programs from its 2001-2002 settlement agreement be carried forward for 2003. The proposed Revenue and Asset Management Program (RAMP), which would allow TCPL to earn a commission on a number of services, was rejected by the NEB. The NEB indicated that to be approved, incentives must induce a company to behave in a manner that improves the operation of the pipeline for its shippers, or must provide mutual benefits to the shippers and the pipeline company. Incentives should be developed such that there was a symmetry between risk and reward, or that the benefits derived by the shippers be commensurate with payment of an incentive commission to the pipeline. Incentives should also affect choices over which the management of the pipeline company has legitimate control.

The RAMP, in the NEB's view, did not satisfy these criteria. The second incentive program, the Fuel Gas Incentive Program (FGIP), was approved by the NEB. The FGIP allowed TCPL to receive a sliding scale incentive amount if it was able to achieve a reduction in the actual amount of fuel gas utilized when compared with the forecasted usage.

g. Transportation by Others

TCPL is able to provide service to Eastern Canada, in part, as a result of its transportation arrangements on the Great Lakes Gas Transmission System (GLGT), which extends from Emerson, Manitoba to St. Clair, Michigan. This type of arrangement is referred to as Transportation by Others (TBO).

TCPL's arrangements with GLGT were scheduled to expire on 31 October 2005, but TCPL had to provide notice of its intentions with respect to renewal by 30 April 2003. Prior to the RH-4-93 decision,[4] TCPL had sought the prior approval of the NEB in respect of all TBO contracting matters. In the RH-4-93 decision, the NEB indicated that it was no longer necessary for a pipeline company to obtain prior approval but the NEB would rather review the prudence of such matters retrospectively when the pipeline company applied to recover the TBO costs in its tolls. TCPL followed this procedure in its 2003 application, but many intervenors presented evidence that TCPL should not be renewing its GLGT capacity at the same level given TCPL's reduced throughput.

In approving the GLGT TBO costs for 2003, the NEB reiterated its position taken in the RH-4-93 decision. However, the NEB thought it appropriate to provide some guidance given the interest that had been generated in respect of the GLGT renewal issue. The NEB indicated that the test should be: "What would a reasonable person, acting in good faith, do in similar circumstances?"[5] Without making any specific ruling on the prudence of renewing GLGT capacity or the terms of any such renewal, the NEB's comments seemed to favour TCPL's position that its existing GLGT contract should be renewed in its entirety.

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4 *Reasons for Decision In the Matter of TransCanada PipeLines Limited, Application dated 8 July 1993, as amended, for New Tolls effective January 1994* (June 1994), RH-4-93 (NEB) [RH-4-93].

5 RH-1-2002, *supra* note 2 at 59.

h. Southwest Toll Zone

In its 2003 application, TCPL proposed the creation of a new toll zone in southwestern Ontario to be called the Southwest Zone (SWZ). The zone would cover all points served on the TCPL pipeline between St. Clair, Ontario, and Dawn, Ontario, which would include the Dawn and Tecumseh gas storage facilities. No intervenors supported the creation of the SWZ.

TCPL argued that Dawn had developed as a key market centre and that a reduced SWZ toll was required in order that TCPL could compete effectively with other pipelines serving this market hub. The SWZ toll would be between $0.16/GJ and $0.19/GJ less than the Eastern Zone toll and its implementation would increase the Eastern Zone by approximately $0.02/GJ.

The NEB approved TCPL's request for the SWZ. The NEB determined that the SWZ was an appropriate response by TCPL to current competitive realities. The SWZ did not offend any of the legislative requirements that tolls must be just and reasonable and not unduly discriminatory. The proposed SWZ also continued to reflect the integrated nature of TCPL's system for the purpose of toll design. Given the intervenors' level of opposition to the SWZ, the NEB required TCPL to provide a comprehensive report with respect to the operations of the SWZ after the first two years of service.

i. Interruptible Transportation Service Toll

TCPL had concerns about the relative value of interruptible transportation (IT) service on its system when compared with firm transportation (FT) service. The bid floor price for IT service was 80 percent of the 100 percent load factor FT toll. TCPL indicated that the low IT toll was resulting in a migration from FT to IT and proposed an IT bid floor price of 110 percent of the 100 percent load factory FT toll. The NEB approved TCPL's request. In designing an appropriate IT toll, the NEB indicated that the primary consideration was to preserve the value of FT service in the current TCPL capacity under-utilization environment. A second consideration was that IT service should be priced at a value that reflects its relative value to FT service. The 110 percent IT bid floor price more appropriately reflected the value of IT service relative to FT service. The NEB also indicated that the retention of a bidding mechanism for IT was desirable from an economic efficiency perspective.

j. Cost of Capital

During the RH-1-2002 proceeding, the Federal Court of Appeal agreed to hear TCPL's appeal of the NEB's RH-4-2001 decision[6] on cost of capital matters for TCPL for the 2001 and 2002 test years. Given this unusual situation the NEB decided to make the tolls for the 2003 test year interim pending the disposition of TCPL's appeal.[7] By making the tolls interim, the NEB preserved the ability to make retroactive adjustments to 1 January 2003.

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6 *Supra* note 3.

7 On 5 April 2004 the Federal Court of Appeal dismissed TCPL's appeal; see *TransCanada Pipelines Ltd. v. National Energy Board* (2004), 319 N.R. 171.

2. OH-1-2003: TRANS-NORTHERN PIPELINES INC. FACILITIES[8]

a. Project Overview

Trans-Northern Pipelines Inc. (Trans-Northern) operates a refined products pipeline that extends over 800 km from Montreal to Nanticoke, Ontario. It is owned by Petro-Canada, Shell Canada Products and Imperial Oil Limited, each of which owns refineries that can utilize this pipeline. Trans-Northern applied to the NEB for a certificate of public convenience and necessity pursuant to s. 52 of the *National Energy Board Act*[9] in respect of approximately 72.5 km of new pipeline, four upgraded pumping stations and three new pumping stations with an estimated total cost of $85.6 million. While the facilities were modest in size, the reason that they were required was to reverse the flow on a significant portion of this pipeline from a west-to-east direction to an east-to-west direction. In connection with this line reversal, Trans-Northern also sought approval from the NEB for Trans-Northern to provide priority access to capacity to certain shippers and for a rolled-in tolling methodology.

b. Reversal of Flow

The direction of flow on the Trans-Northern pipeline has had an interesting history. When the pipeline was first constructed in 1952 product deliveries were made in an east-to-west direction from Montreal to Nanticoke. In 1963 the National Oil Policy was implemented, which precluded the use of imported oil west of the Ottawa Valley. Accordingly, a portion of the pipeline was closed and the portion of the pipeline between Toronto and Kingston was reversed to a west-to-east flow, and terminals along that section were served from Ontario refineries that were refining crude oil produced from Western Canada. In 1973 the west-to-east flow was extended to cover the Ottawa market. In 1982 the Ottawa-to-Montreal segment of the pipeline was reconfigured to permit a bi-directional flow, thus allowing Ontario refineries to deliver their petroleum products to the Montreal market. Trans-Northern's applied for facilities that would now allow most markets in Ontario to be supplied with refined products from Montreal.

Trans-Northern indicated that over the last seven years deliveries from the Toronto area to eastern Ontario had diminished dramatically and that certain portions of its pipeline were operating at less than 20 percent of rated capacity. The need for an east-to-west flow was further demonstrated by the commitment of two shippers to backstop the project by entering into long-term ship-or-pay commitments for transportation from Montreal to Toronto. One of these shippers, Petro-Canada, indicated that the costs to retrofit its Oakville, Ontario, refinery to meet existing and proposed gasoline and distillate sulphur regulations was very significant and that it was examining other methods of sourcing refined products to supply its markets in Ontario. Petro-Canada had recently modified its Montreal refinery to meet regulatory requirements for low sulphur fuels and was planning an expansion of that refinery

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8 *Reasons for Decision In the Matter of Trans-Northern Pipelines Inc. Application dated 24 October 2002 for Capacity Expansion and Line Reversal Facilities* (July 2003), OH-1-2003 (NEB) [OH-1-2003].

9 R.S.C. 1985, c. N-7 [*NEB Act*].

to achieve increased economies of scale. If Petro-Canada was to close its Oakville refinery, it required long-term access to pipeline capacity for products from its Montreal refinery. The second shipper, Ultramar Ltd. (Ultramar), was expanding its Saint-Romuald, Quebec, refinery and was looking to access Ontario markets.

The NEB approved the construction of the facilities. The reversal would increase the utilization of the pipeline, thus benefiting all shippers. While there were other possible non-pipeline alternatives to Trans-Northern's facilities, such as truck and rail options, the evidence of the possible closure of Petro-Canada's Oakville refinery and the expansion of Utramar's refinery demonstrated the need for the project.

c. Priority Access

Trans-Northern had conducted an open season soliciting interest from potential shippers that were prepared to enter into a firm long-term (minimum ten years) ship-or-pay commitment for use of all or part of the capacity on Trans-Northern's system on a priority basis. Petro-Canada and Ultramar were the only two shippers willing to enter into such arrangements. Trans-Northern applied for approval of a priority access of 7,280 m^3/d for Petro-Canada and 1,820 m^3/d for Ultramar. While not objecting to some priority access, certain other refineries took issue with the level of the priority access to be provided to Petro-Canada and Ultramar given Trans-Northern's status as a "common carrier" pipeline.

The NEB approved Trans-Northern's requested level of priority access based primarily on two considerations. First, approximately 900 m^3/d or about 9 percent of the total capacity on the Trans-Northern Pipeline was still available for spot shippers. Second, all potential shippers had an opportunity to participate in priority access as a result of the open season. In addition, the NEB noted that, although pipelines may be the preferred method of transporting refined products, there were the other viable alternatives of truck and rail transportation available.

In reaching its decision, the NEB provided some insight into the duties of a "common carrier" pipeline. The NEB noted that the *NEB Act* itself does not define or use the term "common carrier." The duties of pipeline companies for the transmission of oil and gas are set out in s. 71 of the *NEB Act*. The NEB relied on its previous MH-4-96 decision[10] to conclude that it has broad discretion in determining compliance with the requirements of s. 71. In this earlier decision the NEB noted:

> [C]ompliance with the common carrier provisions is determined by a test of reasonableness, which is a relative concept. Section 71 of the *NEB Act* is consistent with [the] common law approach because it permits the Board to tailor the statutory obligations of both oil and gas pipelines to fit any unique circumstances which may exist. Thus, the Board can increase or decrease the statutory common carrier obligations of an oil, gas or commodity pipeline in respect of their carriage of oil, gas or another commodity.[11]

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10 *Reasons for Decision In the Matter of PanCanadian Petroleum Limited, Application dated 26 July 1996 for an order requiring Interprovincial Pipe Line Inc. to transport natural gas liquids for PanCanadian Petroleum Limited from Kerrobert, Saskatchewan* (February 1997), MH-4-96 (NEB).

11 *Ibid.* at 11.

In applying this test to the proposed Trans-Northern facilities, the NEB indicated that allowing for long-term contracting of transportation of some of the capacity on an oil pipeline was not inconsistent with a "common carrier" obligation, although it would be important that some capacity remain available for spot shipments from all sources and to all locations on the pipeline. However, the NEB also recognized that shippers that are willing to enter into ship-or-pay agreements and to backstop projects have a legitimate interest in secure access to the facilities. Without long-term contracts indicating that the capacity will be used and that the project costs would be recovered, the NEB recognized that many projects might not proceed.

In the end, the NEB was required to use its judgement and balance the various interests to determine the appropriate level of capacity that would be available for spot shippers. The NEB concluded that Trans-Northern did meet its common carrier obligations under the *NEB Act* and that an order exempting Trans-Northern from the provisions of s. 71 of the *NEB Act* was not required.

d. Rolled-in Tolling

Trans-Northern had applied for the new facilities to be tolled utilizing a rolled-in toll methodology. No intervenor objected to this approach and the NEB approved the rolled-in toll methodology.

e. Review of Decision OH-1-2003

The NEB issued its decision on 7 August 2003. On 3 September 2003 Petro-Canada announced its intention to shut down its Oakville refinery operations and consolidate its Eastern Canada refining operations at its Montreal refinery. The shutdown was timed for 1 1 January 2005, the deadline for complying with low sulphur gasoline legislation. On 29 September 2004 the Communication, Energy and Paper Workers Union of Canada (CEP), which represents a number of the employees at Petro-Canada's Oakville refinery, applied to the NEB to review the OH-1-2003 decision in total, and in the interim, to stay the decision. It had not participated in the NEB proceeding. On 7 November 2003 the NEB denied the CEP's application for review and the request for a stay.

3. GH-1-2003: ENCANA EKWAN PIPELINE INC. FACILITIES[12]

a. Project Overview

EnCana Ekwan Pipeline Inc. (EnCana Ekwan) applied to the NEB for a certificate of public convenience and necessity in respect of a new pipeline that would connect the EnCana Oil & Gas Partnership's (EnCana O&G) Sierra Gas Plant located in British Columbia to the NOVA Gas Transmission Ltd. system in Alberta. The 83-km NPS 24 pipeline and related facilities were estimated to cost $55 million. The design capacity of the pipeline was

[12] *Reasons for Decision In the Matter of EnCana Ekwan Pipeline Inc., Application dated 17 March 2003 for the construction and operation of the Ekwan Pipeline* (September 2003), GH-1-2003 (NEB) [GH-1-2003].

approximately 11.8 $10^6m^3/d$ (418 MMcf/d), although initial throughput was expected to be significantly less. The sole shipper on the pipeline was EnCana O&G. The NEB approved EnCana Ekwan's application.

b. Aboriginal Consultation

One issue in the GH-1-2003 hearing related to Aboriginal consultation. The pipeline crossed lands that were covered by Treaty 8. EnCana Ekwan consulted with three First Nations — the Dene Tha', Fort Nelson and Prophet River — each of which EnCana Ekwan believed to have an interest in the area. EnCana Ekwan was able to enter into a separate benefits agreement with each of these three First Nations and each provided a letter of support for the project. Another Treaty 8 signatory, the Duncan's First Nation, filed an application for intervenor status, indicating its interests in the project were its treaty rights to hunt, fish, trap and gather and in respect of unsurrendered resources. EnCana Ekwan had not contacted the Duncan's First Nation initially as its reserve lands were located approximately 300 km south of the pipeline and the northern boundary of the Duncan's First Nation claimed traditional territory was still approximately 120 km south of the pipeline.

The Duncan's First Nation did not pre-file any written evidence but at the hearing presented some documents that it used during its cross-examination of EnCana Ekwan. In final argument, the Duncan's First Nation argued that the application should be rejected as being incomplete for failing to address the socio-economic impacts the project would have on Treaty 8 members and that EnCana Ekwan had not considered the rights of Treaty 8 First Nations to be informed and to consent to the project.

The NEB was satisfied that EnCana Ekwan had used appropriate means to determine which Aboriginal groups may have an interest in the area of its proposed pipeline, and to adequately address any concerns that they had. In respect of the Duncan's First Nation, the NEB noted that the applicant had sufficiently addressed any impact the pipeline may have on Treaty 8 members. The environmental screening of the project determined that it was not likely to cause significant adverse impacts on any of the Aboriginal trappers and hunters who use the land near the pipeline. Given that the Duncan's First Nation did not provide any evidence that any of its treaty or Aboriginal rights that it may have would be infringed by the pipeline, the NEB determined that there is no obligation or duty for either the Crown or EnCana Ekwan to consult with the Duncan's First Nation.

c. Socio-economic Impact

A second issue related to the fact that the pipeline would transport gas produced in British Columbia to Alberta rather than on the Westcoast Energy Inc. pipeline system located in British Columbia. The Northern Society of Oilfield Contractors and Service Firms (NSOCSF) was concerned that the pipeline would reduce the possibility of expanding gas transportation systems within British Columbia and therefore negatively affect the regional economy and jobs in the region. The City of Fort St. John had similar concerns and suggested that discussions be initiated on broader regional matters.

The NEB determined that EnCana Ekwan had satisfactorily assessed the socio-economic impacts of the project and indicated that both short-term and long-term benefits to the local communities would likely occur given EnCana Ekwan's efforts to ensure that local workers and businesses were afforded business and employment opportunities. The broader issues of resource development impacts on the northeastern region of British Columbia raised by the NSOCSF and the City of Fort St. John were considered to be beyond the scope of the proceeding.

d. Duration of Regulatory Process

A final matter that should be noted is the ability of the NEB to process an application for a certificate in a very timely manner. Although the Ekwan pipeline was a relatively small pipeline, EnCana Ekwan's 17 March 2003 application was set down for hearing on 25 April 2003, the public hearing was held on 28 and 29 July 2003 and a decision was issued by the NEB on 18 September 2003. This allowed Governor-in-Council approval of the certificate and all plan, profile and book-of-reference authorizations to be obtained by the scheduled construction commencement date of 1 December 2003. The Ekwan pipeline was placed in service, on schedule, on 1 April 2004.

4. GH-4-2001: GEORGIA STRAIT CROSSING PIPELINE LIMITED ON BEHALF OF GSX CANADA LIMITED PARTNERSHIP, FACILITIES[13]

a. Project Overview

The Georgia Strait Crossing Project was a new international pipeline that would allow natural gas to be transported from the Sumas, Washington/Huntingdon, British Columbia market hub to markets in northwestern Washington and on Vancouver Island. The project was jointly sponsored by British Columbia Hydro and Power Authority (BC Hydro) and Williams Gas Pipeline Company LLC. The Canadian portion of the Georgia Strait Crossing Project (GSX) consisted of approximately 60 km of NPS 16 pipeline and related facilities starting from a point on the international border in Boundry Pass, British Columbia, and interconnecting with the existing Terasen Gas (Vancouver Island) Inc. pipeline at a point west of Shawnigan Lake and south of Duncan on Vancouver Island. Approximately 44 km of the GSX pipeline would be a marine pipeline, and there would be a horizontal directional drilled shore crossing near Manley Creek, British Columbia. The design capacity of the GSX pipeline was 2.71 $10^6 m^3/d$ (95.7 MMcf/d) with an estimated cost of $139.3 million. The gas to be transported on the proposed pipeline would be used primarily to supply two cogeneration projects, the Vancouver Island Generation Project (VIGP) to be located near Nanaimo and the existing Island Cogeneration Project (ICP) located at Campbell River.

13 *Reasons for Decision In the Matter of Georgia Strait Crossing Pipeline Limited on behalf of GSX Canada Limited Partnership, GSX Canada Pipeline application dated 24 April 2001* (November 2003), GH-4-2001 (NEB) [GH-4-2001].

b. Joint Review Process

Georgia Strait Crossing Pipeline Limited (GSX PL) had filed a preliminary submission on 7 March 2000 and as a result the NEB conducted a number of sessions to seek comments on the structure of the environmental assessment and regulatory review process in respect of the GSX pipeline. As the GSX pipeline contained a marine segment it constituted an offshore gas pipeline, which under the *Comprehensive Study List Regulations*[14] required a comprehensive study environmental assessment to be carried out under the *Canadian Environmental Assessment Act.*[15] On 4 October 2001 the federal Minister of the Environment announced that the GSX pipeline would require an independent environmental assessment review panel.

On 24 April 2001 GSX PL filed its application for a certificate of public convenience and necessity pursuant to s. 52 of the *NEB Act.* This initiated discussions between the NEB and the Minister of the Environment on an agreement that would coordinate the environmental assessments required under the *CEAA* and the *NEB Act.* An agreement was finalized on 20 September 2001 when an independent Joint Review Panel (JRP) was appointed. Two members of the JRP were regular NEB members, Elizabeth Quarshie and Rowland Harrison, while the third, the Honourable Bryan Williams, was appointed a temporary member of the NEB. The mandate of the JRP was to act as a joint review panel under the *CEAA* to make recommendations to the Minister of the Environment and as a NEB panel to consider matters relevant to a certificate application under the *NEB Act.*

A hearing order was issued on 9 November 2001 with a scheduled 17 June 2002 commencement date for the public hearing. As a result of the number of preliminary issues respecting the scope of the environmental review in respect of the end use consumption of gas, the status of Crown consultation activities with First Nations and alternatives to the project, the start of the hearing was delayed. The hearing finally commenced on 24 February 2003, lasted 17 days and generated significant participation by the general public.

The JRP released its report under the *CEAA* on 30 July 2003 that reviewed the environmental effects of the project and appropriate mitigation measures and follow-up programs. The Government of Canada's response to the *CEAA* report was released on 21 November 2003. The NEB released its decision under the *NEB Act* approving the issuance of a certificate on 28 November 2003, approximately 45 months after GSX PL had initiated the regulatory review process.

c. Facilities and Pipeline Safety

Given that this was one of the few marine pipelines in Canada and was to be located in a region of high seismic activity, pipeline design, construction methods and pipeline safety were significant issues in this proceeding. For the most part, the NEB accepted GSX PL's proposals, although conditions to the certificate would provide the NEB with a further opportunity to review these matters at a later date. GSX PL had prepared a number of seismic

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14 S.O.R./94-638.

15 S.C. 1992, c. 37 [*CEAA*].

and geotechnical reports during the proceeding, which for the most part were based on a design criteria that there is a 10 percent probability that the design ground motions will occur or be exceeded within a 50-year time period. The NEB conditioned the certificate requiring GSX PL to design to a more conservative 2 percent in a 50-year probability of exceedance. Another significant condition that was imposed on GSX PL was the requirement for an independent third-party verification of the design, construction and testing of the marine portion of the pipeline. The NEB appears to have required this condition given the level of public concern, the rarity of marine pipelines in Canada, the high seismic activity in the area, the time it would take to repair any failure in the marine pipeline and the potentially significant economic and social implications of an extended interruption in service to the two Vancouver Island cogeneration facilities.

d. Environmental Matters

The potential environmental effects of the project under the *CEAA* were considered by the JRP and the JRP found that if all of the JRP's recommendations and GSX PL's environmental commitments were implemented, the GSX pipeline was not likely to cause significant adverse environmental effects. In considering environmental effects under the *NEB Act*, the JRP considered the additional matter of the environmental effects of the combustion of gas at the proposed new VIGP cogeneration plant. Matters addressed included the potentially harmful emissions from the VIGP, the impact on the overall air quality of the region and greenhouse gas emissions. GSX PL provided evidence that the VIGP would have no significant cumulative air quality impacts given that it was to be located adjacent to an existing pulp and paper mill, which was already a significant source of emissions in the region.

In respect of greenhouse gas emissions, one of the owners of the GSX pipeline, BC Hydro, made a voluntary commitment to offset 50 percent of the increase in greenhouse gas emissions in the period through 2010 in respect of both the VIGP and the existing ICP. A greenhouse gas emission offset is a project that compensates for greenhouse gas emissions at one source by reducing, capturing or storing emissions at another source. A majority of the JRP decided that BC Hydro's commitment should be treated through a certificate condition. JRP member Harrison dissented on the need to impose a certificate condition on GSX PL. He noted the potential difficulty in enforcing such a condition against GSX PL if BC Hydro did not meet its voluntary commitment level. He also indicated that turning BC Hydro's voluntary commitment into a certificate condition would clearly discourage such voluntary initiatives in the future.

e. Socio-economic Matters

During the hearing the Tseycum First Nation, Cowichan Tribes and the Sencot'en Alliance (representing four additional First Nations) reached an agreement with GSX PL and indicated that their concerns had been addressed. The Sencot'en Alliance requested that the JRP incorporate certain portions of its agreement with GSX PL as part of any JRP approval. The JRP refused to do so, as it believed that if a dispute arose from a private agreement it should be resolved by the courts and not the NEB.

f. Consultation with First Nations

One of the major reasons for the significant delay in getting the GSX PL application to the hearing stage related to the issue of Crown consultation with the various First Nations in the project area. BC Hydro, which was consulting on behalf of GSX PL, initiated its consultation process with the First Nations commencing in 1999 and continued its consultations throughout the proceeding. The Cowichan Tribes, Tseycum First Nation and the Sencot'en Alliance all initially asserted that the GSX pipeline would have an impact on their treaty and Aboriginal rights and that there was no evidence that Crown consultation had taken place.

During 2002, the JRP issued a number of information requests to GSX PL and the federal and provincial Crown intervenors in respect of any activities undertaken relating to Crown consultation. It was only near the end of 2002 that any preliminary meetings between the federal Crown and certain First Nations commenced. However, no progress was made on substantive issues. It must be recognized that the Supreme Court of Canada will very likely clarify the "duty to consult" in the near future, as it is scheduled to review a recent British Columbia Court of Appeal decision dealing with the issue.[16] In deciding to proceed with the hearing, the JRP indicated that if it was not satisfied at the conclusion of the evidentiary phase of the hearing that meaningful consultation had been carried out, the JRP did not intend to proceed to its final deliberations in respect of GSX PL's application.

Ultimately, the JRP did not have to decide this issue as prior to the close of the hearing the Tseycum First Nation, the Cowichan Tribes and the Sencot'en Alliance all indicated that they had entered into agreements with GSX PL and were each prepared to accept that Crown consultation had been adequate to permit the issuance of a certificate to GSX PL. They each withdrew their interventions in this proceeding.

g. Markets and the Need for the Pipeline

BC Hydro was the sole owner of Powerex Corporation (Powerex), which was the sole shipper on the GSX pipeline. BC Hydro was also the ultimate owner of the VIGP and all of the power output of the other cogeneration facility; ICP was contracted to BC Hydro. Given this level of corporate interrelationship the JRP felt that it was appropriate to go beyond the Powerex transportation contract to evaluate the need for gas on Vancouver Island. The two cogeneration facilities were not subject to NEB jurisdiction, so the JRP was starting to stray into areas of provincial jurisdiction.

The JRP was interested in the long-term viability of these two cogeneration facilities. GSX PL indicated that an electricity shortfall on Vancouver Island could occur as early as the 2006-2007 period given electricity load growth and the planned retirement of the two subsea cable systems currently delivering electricity from the mainland to Vancouver Island.

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16 *Haida Nation v. British Columbia (Minister of Forests)* (2002), 172 B.C.A.C. 75, leave to appeal to S.C.C. granted, [2002] S.C.C.A. No. 417. The Supreme Court of Canada issued its decision in this case on 18 November 2004, [2004] 3 S.C.R. 511.

The JRP concluded that any additional gas-fired generation facilities on Vancouver Island would require a new pipeline to be built and that given the planned retirement of the subsea cables, there was clearly a need for another source of electricity. Subsequent to the close of the hearing, on 8 September 2003, the British Columbia Utilities Commission denied an application to construct the VIGP as it determined that it had not been established that the VIGP was the most cost-effective means to meet the power needs of Vancouver Island.[17] The JRP noted this post-hearing event and conditioned GSX PL's certificate to require that GSX PL provide evidence to the NEB that the VIGP had received regulatory approval before it could commence construction of the GSX pipeline.

h. Subsea Cable Alternative to the Pipeline

A number of intervenors in this proceeding took the position that BC Hydro should upgrade or replace the existing subsea cable systems as an alternative to construction of the GSX pipeline. GSX PL and the provincial government intervenors took the position that evidence on the subsea cables was not relevant to the JRP's deliberations under the *NEB Act* and submitted that it was not the role of the JRP to determine how the electrical requirements of Vancouver Island were to be best served since that was a provincial matter.

The JRP determined that the matter of the subsea cables was relevant to their decision. It noted that s. 52 of the *NEB Act* conveyed a broad discretion on the NEB to have regard to all considerations that appear relevant to the NEB. Section 52(e) also specifically allowed the NEB to consider any public interest that, in the NEB's opinion, may be affected by the granting or the refusing of the application. The JRP determined that there are two ways to determine whether information is relevant to a s. 52 determination. First, information would be relevant if it is a matter that pertains to the application and is a matter over which the JRP has regulatory control. Second, information can be relevant if it is a matter that would be useful to the JRP in making its determination under s. 52, but is a matter over which the JRP cannot exert regulatory control. The JRP recognized that as it could not regulate electricity matters in British Columbia, the first test for relevancy was not satisfied. However, the JRP felt its evidence of the subsea cables was relevant under their second relevancy test. The subsea cables had a sufficient connection or nexus to GSX PL's application that other possible energy alternatives such as solar power or wind power did not.

The JRP noted that the fact that there might be a subsea cable alternative meant that the consequences of a denial of GSX PL's application, which would likely result in the VIGP not proceeding, would not be as significant as it would be in the absence of the subsea cable alternative. The JRP indicated their view that the appropriate provincial authorities should determine whether or not a subsea cable would be the best way to deliver electricity to Vancouver Island.

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17 *Decision In the Matter of Vancouver Island Energy Corporation (A Wholly-Owned Subsidiary of British Columbia Hydro and Power Authority), Vancouver Island Generation Project, Application for a Certificate of Public Convenience and Necessity* (8 September 2003), (BCUC).

i. Public Convenience and Necessity Test

The JRP indicated that under s. 52 of the *NEB Act* there was no one specific test to determine when it is in the public convenience and necessity to issue a certificate. In considering all the relevant evidence, the JRP had to weigh the benefits and the burdens of the GSX PL application. In doing so the JRP concluded that a certificate should be granted.

5. EH-1-2000: SUMAS ENERGY 2, INC., FACILITIES[18]

Sumas Energy 2, Inc. (SE2) applied for a certificate of public convenience and necessity pursuant to s. 58.16 of the *NEB Act* in respect of an 8.5 km international power line originating at the Canada/United States border near Sumas, Washington and running to a BC Hydro substation in Abbotsford, British Columbia. The powerline, which included both above-ground and underground facilities, would have allowed SE2 to transport electricity from a proposed powerplant, to be constructed in the United States by one of its affiliates, to the BC Hydro grid in Canada. Thirty-nine hearing days were required to address the SE2 application and related motions. On 4 March 2004 the NEB denied the application despite the NEB's earlier 30 December 2003 environmental screening report under the *CEAA* that concluded that the powerline would not be likely to cause significant adverse environmental effects.

While it does not relate to pipeline facilities, the EH-1-2000 proceeding addressed a number of very significant issues that could be equally applicable to a NEB pipeline application. The legislative requirements under the *NEB Act* in this area are quite similar for powerlines and pipelines. The EH-1-2000 proceeding had a huge level of public participation. Over 400 parties registered as intervenors and 22,000 letters of comment were filed, most in opposition to the project. Perhaps as a result of the high public participation level, the NEB went to some length in the EH-1-2000 decision to elaborate on: its role; its legislative mandate; its procedures; and elements of administrative law. Given the extent of the NEB's discussion and the fact that the decision is one of the rare cases where the NEB has denied a facilities application, it is an important decision for all involved in NEB regulated activities.

Significant items that were addressed in this proceeding included:

- the role of the NEB;
- the use of conditions in certificates;
- the public interest and the public convenience and necessity test;
- the need for the power plant;
- the NEB's responsibility to protect competition in the marketplace but not the position of any particular competitor;
- the levels of direct and indirect benefits to Canadians;

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18 *Reasons for Decision In the Matter of Sumas Energy 2, Inc., Application dated 7 July 1999, amended 23 October 2000, for the construction and operation of an International Power Line* (March 2004), EH-1-2000 (NEB) [EH-1-2000].

- the scope of the *CEAA* review process versus the *NEB Act* review process of environmental impacts of the powerplant to be located in the United States;
- air quality issues, groundwater impacts and noise relating to the powerplant;
- the NEB's role in Crown consultation with First Nations;
- the need for Crown consultation where Aboriginal rights had not been legally established or proven;
- the impact of the powerline on any asserted Aboriginal rights;
- the balancing of project benefits and project burdens in determining whether a project is in the public interest;
- public interest considerations going beyond mere compliance with regulatory standards;
- the significance of overwhelming community interest against a project; and
- the role, responsibilities and conduct of intervenors.

B. ALBERTA ENERGY AND UTILITIES BOARD DECISIONS

1. AEUB DECISION 2003-029: *PRINCE RESOURCE CORPORATION, REVIEW OF ABANDONMENT COSTS ORDER NO. ACO 2001-06*[19]

Prince Resource Corporation (Prince) was issued an Abandonment Cost Order by the AEUB's Corporate Compliance Group (CCG) requiring it to pay well abandonment costs. Prince brought an application under s. 40 of the *Energy Resources Conservation Act*[20] to have the AEUB review the Abandonment Costs Order. Prince was the licensee and a working interest participant in a well, but the Surface Rights Board terminated its right to access the well site. The CCG issued an Abandonment Order and, upon Prince failing to carry out the abandonment, carried out abandonment operations. The CCG offset the costs with revenues from salvaged equipment and added the 25 percent penalty authorized by the *Oil and Gas Conservation Act*.[21]

The AEUB held a written hearing before one AEUB member. Prince argued that a quorum of three AEUB members was required for a hearing. The AEUB ruled that the sole AEUB member was simply exercising the powers of the AEUB for the purposes of taking evidence or acquiring the necessary information for the purposes of the AEUB member's report. In the review hearing, the sole member's report was only to be a recommendation to the AEUB.

Prince also argued that it was entitled to an oral hearing. The AEUB dismissed this objection, noting that its *Rules of Practice*[22] allowed it to hold written hearings and that a party to a written hearing could request an oral hearing. Prince had never done so and only raised the issue about the inadequacies of a written hearing in final argument.

Prince also challenged the AEUB's ability to delegate to the CCG decisions regarding Abandonment Orders. However, the AEUB ruled that Prince could not challenge the

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19 (28 April 2003), AEUB Decision 2003-029 (AEUB).
20 R.S.A. 2000, c. E-10.
21 R.S.A. 2000, c. O-6 [*OGCA*].
22 *Alberta Energy and Utilities Board Rules of Practice*, Alta. Reg. 101/2001, as am.

Abandonment Order some two years after it was issued and that this hearing dealt with the Abandonment Cost Order. The AEUB also noted that s. 18 of the *Alberta Energy and Utilities Board Act*[23] authorized the AEUB to delegate any of its powers or duties to officers or employees of the AEUB.

Finally, Prince challenged the reasonableness of the Abandonment Costs Order. The AEUB, however, ruled that the costs were the actual costs and were therefore reasonable.

2. AEUB DECISION 2003-049: *VINTAGE PETROLEUM CANADA, INC., APPLICATIONS FOR SPECIAL GAS WELL SPACING, STURGEON LAKE SOUTH FIELD*[24]

Vintage Petroleum Canada, Inc. (Vintage) submitted applications to establish holdings for gas production. The pool in question had 29 wells capable of production. Vintage had an interest in all 29 wells. Vintage wanted a minimum of 400 m separation between each well in the same pool and a 200 m setback from the boundaries of the holding, with up to three wells per section. The existing spacing was one well per pool per section.

Paramount Resources Ltd. (Paramount) had an interest in four wells in the pool but Paramount's wells were outside of the area of Vintage's applications. Paramount objected to Vintage's applications on the grounds that inequities would result that would benefit Vintage if reduced spacing only occurred in certain portions of the pool as opposed to the entire pool. Paramount felt that all pool owners should reach agreement on depletion plans before reduced spacing was approved. Paramount argued that additional wells would only accelerate production from the pool and not lead to any significant incremental gas recovery. Paramount believed inequitable drainage would result from Paramount's lands.

The AEUB examiners felt that the generally low production rates from the existing wells and the limited recoverable reserves suggested that the existing wells were not effectively draining a one-section drilling spacing unit. They concluded that a significant amount of the reserves would not be produced by the existing wells and the reservoir would benefit from additional wells.

The examiners considered what well density would represent orderly and efficient development and an optimum level for gas conservation. Once established, drainage concerns could be reduced by drilling appropriate, competitive wells. The examiners recognized that if the well density exceeded an optimum level, subsequent wells targeting a small resource might not be orderly or economic. In such a case, an equitable balance may not be reached by drilling offset wells, and unfair drainage may occur.

In the end, the examiners believed that the existing wells were not adequately draining the pool. They felt that the 200 m buffer minimized the potential for offsite draining caused by a second well in a section and that there were sufficient reserves to warrant Paramount drilling offset wells to mitigate drainage concerns.

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23 R.S.A. 2000, c. A-17.

24 (23 June 2003), AEUB Decision 2003-049 (AEUB).

The examiners therefore allowed two wells per section (instead of the three requested by Vintage), with a minimum inter-well distance of 400 m and a 200 m buffer. However, Vintage was required to undertake additional pressure surveys for existing wells above those normally specified in the AEUB's *Guide 40: Pressure and Deliverability Testing Oil and Gas Wells — Minimum Requirements and Recommended Practices.*[25]

3. AEUB DECISION 2003-050: *BURMIS ENERGY LTD., APPLICATIONS FOR LICENCES FOR WELLS, GAS BATTERIES AND ASSOCIATED PIPELINES, WILDWOOD FIELD*[26]

Originally, applications to licence sour wells and associated facilities were filed by Elk Point Resources Inc., but it was then acquired by another party who then farmed out the lands to Burmis Energy Inc. (Burmis). The AEUB agreed to allow for transfer of the applications to Burmis.

The applications included those for pipelines that connected the wells to an existing battery. A one-year extension to the normal one-year period to construct the pipelines was requested on the grounds that an extra year was needed to allow for a reasonable assessment of whether the wells were capable of commercial production.

The landowners objected, citing issues of water quality, impacts on farming, health impacts from flaring and fugitive emissions, reclamation and quality of life. They argued that the pipeline applications were premature due to the uncertainty of the quality and quantity of gas that might be producible.

The AEUB accepted that if the wells were commercially productive then surface facilities and pipelines would be required. The AEUB recognized that there may be some uncertainty with respect to whether the applied for facilities would actually be required; however, the AEUB reiterated its practice to encourage companies to submit applications associated with the well licence applications when a public hearing is held. This allowed the possible impacts of the entire project to be considered by potentially affected parties and the AEUB. The AEUB was satisfied that the batteries and pipelines as applied for were appropriate if the wells were productive.

With respect to the request to extend the normal one-year construction window, the AEUB was not persuaded that an extension was necessary. It felt that an evaluation of the productive potential of the wells should occur in a reasonable time, and therefore, the extension beyond the normal one-year term was not granted.

As for the landowners' concerns that the wells would interfere with groundwater supplies, the AEUB found the proposed drilling practices to be appropriate. It noted the applicant's undertaking to test the landowners' wells before drilling so as to establish a baseline of water quality and quantity. However, the AEUB refused to impose a condition that Burmis agree to drill a new water well at its cost if Burmis' activities damaged the water well.

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25 May 1999 (AEUB).

26 (23 June 2003), AEUB Decision 2003-050 (AEUB).

The landowners also raised an interesting issue about the corporate capacity of Burmis to take on numerous responsibilities given its small size. Burmis' witnesses admitted they were not fully conversant with incident investigation and reporting procedures, and that they did not have specific training or experience in emergency response or health, safety and environment programs. The AEUB expected that Burmis would be diligent in ensuring that its operations personnel and contractors were fully familiar with its health, safety, environment and corporate emergency response programs. The AEUB further expected that Burmis would ensure that its staff, with primary responsibility for the implementation of its emergency response and health, safety and environment compliance programs, were adequately trained and qualified to assume these roles. The AEUB viewed this as particularly important when so much responsibility was vested with one leader. The AEUB noted that Burmis' health, safety and environment manual was general in nature, and it expected that Burmis would take steps to ensure that specific practices were implemented to address unique aspects of individual facilities.

4. AEUB DECISION 2003-057: *BELAIR ENERGY CORPORATION, APPLICATION FOR A WELL LICENCE, LOCHEND FIELD*[27]

Belair Energy Corporation (Belair) applied to the AEUB for a licence to drill a sour gas well. Area landowners objected.

One intervenor suggested alternative surface locations for the well. Belair responded that one of the suggested alternative locations was feasible but would increase the cost of the well by 30 percent, and cause the emergency planning zone (EPZ) to include three additional residences and a golf course. Further, the suggested new location was more likely to disturb wildlife and require a longer access road. The site chosen and preferred by Belair was on the previously disturbed land.

The AEUB concluded that the originally chosen site was best, as it would have less impact than the alternatives. The AEUB expressly stated that it did not consider the additional costs or the change in the EPZ to be relevant.

The intervenors also pointed out that a Sprague's Pipit was spotted within 200 to 500 m of the well site. The Sprague's Pipit is considered a threatened species under the guidelines set by Alberta Sustainable Resources Development (ASRD) and the Committee on the Status of Endangered Wildlife in Canada. Belair committed to following ASRD's guidelines to restrict drilling outside of 15 May to 15 July if a Sprague's Pipit's nest was found within 100 m of the well. Unfortunately, the AEUB did not comment on this potential *Species At Risk Act*[28] concern in its decision report.

A further issue was with respect to the completeness of Belair's public notification and consultation program. Some intervenors were critical of Belair failing to include an application for a pipeline and further wells. Belair's position was that the well was exploratory and it was therefore uncertain if further facilities would be required. The AEUB

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27 (15 July 2003), AEUB Decision 2003-057 (AEUB).

28 S.C. 2002, c. 29 [*SARA*].

agreed, noting that if the well were drilled in a development setting there would be greater certainty, thereby potentially enabling Belair to share more information with the community.

Finally, the intervenors noted that Belair had suffered financial losses in the previous year and that it was exploring "strategic alternatives," which might include a sale. They suggested that the AEUB suspend the issuance of an approval until future ownership of the company was known. The AEUB disagreed, noting that sales and mergers in the industry are common. The AEUB pointed out that any transfer of the licence would be subject to AEUB approval.

5. AEUB DECISION AND ADDENDUM DECISION 2003-046: *VERMILION RESOURCES LTD., CLEAR ENERGY INC. AND TUSK ENERGY INC., RATEABLE TAKE, SPECIAL OFF-TARGET PENALTY, SHANE KISKATINAW D POOL*[29]

On 14 February 2003, Vermilion Resources Ltd., on behalf of itself, Clear Energy Inc. and TUSK Energy Inc. (collectively Vermilion) brought two applications concerning the Shane Kiskatinaw D Pool. First, it sought an order under s. 36 of the *OGCA*[30] for a rateable take order from the D Pool among four wells, two of which Vermilion held interests (the 12-19 and the 4-24) and two of which the interests were held by Monolith Oil Corp. (Monolith), Talisman Energy Inc. (Talisman) and others (the 2-30 and 2-23). Vermilion asked that the rateable take order be effective December 2002.

In the second application, Vermilion requested a special off-target penalty and allowable production rate be imposed on the 2-30 well pursuant to s. 4.060(2) of the *Oil and Gas Conservation Regulations*.[31] Vermilion asked that the special off-target penalty be made effective to 5 February 2003.

All four wells in this pool were highly productive. At the time of the hearing in May 2003, production from these four wells was 1.485 $10^6 m^3/d$ (52.55 MMcf/d). However, the life of the D Pool was very short. Hence, Vermilion felt it did not have a reasonable opportunity to obtain an equitable share of production from the pool. Vermilion believed the life of the pool was only about nine months at current production rates, while Monolith felt production would last two years, and maybe as long as five years.

Talisman supported Vermilion's applications, but they were opposed by Monolith.

The first issue dealt with by the AEUB was delineation of the D Pool, and specifically the location of the reserves, if any, that were not in the main channel constituting the D Pool. After reviewing the technical evidence, the AEUB found that there continued to be uncertainty regarding the location of the reserves that were not in the main channel. As it was not possible to map the entire D Pool in a reliable manner with current data, the AEUB concluded that there was no reason to amend its current pool order of four sections.

29 (5 June 2003, 7 August 2003), AEUB Decision 2003-046 plus Addendum (AEUB).
30 *Supra* note 21.
31 Alta. Reg. 151/1971, as am. [*OGCR*].

The AEUB then dealt with the request for the special off-target penalty. Vermilion argued that Monolith was recovering more than six and a half times the reserves estimated under the Monolith lands. Vermilion requested a special off-target penalty be assessed to protect correlative rights. Monolith argued that off-target penalties were intended to reduce, but not eliminate, the impacts of drainage from an off-target well. It argued that imposing a special penalty would be inappropriate.

The AEUB stated that off-target penalties are meant to mitigate lease line drainage from off-target wells. However, where the penalty appeared in a given circumstance to be ineffective in protecting correlative rights, a special off-target penalty could be imposed. In this case, the AEUB noted that the pool in question was not typical of most pools in Alberta in that it was unusually permeable and highly productive. The AEUB concluded that a special off-target penalty would not fully address equity issues for all parties with interests in the pool. The AEUB then considered whether there was inequitable drainage, whether Vermilion had reasonable opportunities to address the drainage and whether for conservation reasons limits on production should be imposed. The AEUB issued a rateable take order to address Vermilion's concerns.

6. AEUB DECISION 2003-080: *STYLUS EXPLORATION INC., APPLICATION FOR APPROVAL TO PRODUCE GAS, HARDY FIELD* [32]

Stylus Exploration Inc. (Stylus) applied for approval under s. 3(4) of the *Oil Sands Conservation Regulation*[33] to produce from various intervals in four wells. AEUB staff opposed the application, arguing that a significant amount of bitumen existed in the area. They argued that most of the Wabiskaw-McMurray gas in the area was associated with underlying bitumen, similar to both the Surmount and Chard-Leismer areas.

The AEUB conducted an interim expedited hearing. Its decision report does not contain the view of the hearing participants but only the AEUB's views.

The AEUB found that there was potentially recoverable bitumen in the area and as such it warranted protection. However, in some of the wells there was a basal mudstone more than 0.5 m thick and therefore the risk of communication between the bitumen and the gas zones was low. However, in other wells, it was less than 0.5 m, and would therefore not provide an effective seal between zones. The AEUB therefore ordered that such wells should remain shut-in.

7. AEUB DECISION 2003-081: *CANADIAN NATURAL RESOURCES LIMITED, APPLICATION FOR SPECIAL OIL WELL SPACING, LLOYDMINSTER FIELD*[34]

Canadian Natural Resources Limited (CNRL) applied to establish holdings over portions of three sections for oil production. It sought a condition that each producing well be at least 100 m from each other well producing from the same pool, with no producing well being less

32 (4 November 2003), AEUB Decision 2003-080 (AEUB).

33 Alta. Reg. 76/1988, as am.

34 (4 November 2003), AEUB Decision 2003-081 (AEUB).

than 50 m from the boundary of the holding. Further, the total number of wells per drilling spacing unit (DSU) was limited to that set by an earlier spacing unit order. Some landowners with interests in both the surface and the minerals with respect to some of the lands included in the application objected.

CNRL submitted that the special oil well spacing was needed both to improve recovery of heavy oil by drilling at optimal geologic locations and to increase its flexibility in locating well sites to minimize or eliminate any adverse effect on landowners. CNRL argued that its holdings application would not result in a greater number of wells being drilled than permitted by existing spacing, but would allow multiple wells being directionally drilled from a single pad. The existing DSU was one legal subdivision (LSD) for some of the lands and one-half LSD for others.

The landowners claimed there was no evidence to support reduced spacing. They believed the purpose of the application was to reduce the spacing to avoid off-target penalties.

The AEUB noted that the one LSD and one-half LSD spacing was set by a previous AEUB order and that CNRL was not asking for that previous order to be revised. The AEUB found that the holdings would provide increased flexibility in the location of the wells from both a surface and subsurface perspective. The AEUB made it very clear that the approval of the holding would not provide for or allow the drilling of any more wells than could have otherwise been permitted under the existing DSU order, nor would it result in the reduction of the DSU size beyond that already approved. The AEUB also emphasized that approval of the applied for holding did not alleviate the necessity for CNRL to submit well licence applications for any wells to be drilled within the proposed holding. CNRL was also required to submit an application for any further reduction in the effective size of the DSUs. All of the aforementioned applications would be considered on their own merits and in full compliance with the AEUB's procedures and practices respecting the handling and disposition of new applications.

The AEUB also noted that the proposed holding would not change the number of wells permitted to be produced per pool, per DSU. The AEUB felt that the holding would increase CNRL's flexibility to respond to the landowner's concerns. The AEUB made it very clear that the *OGCR*[35] regulated well density to one producing well per DSU per pool, with the bottom hole location of that well to be located within the defined target area for the DSU. The regulation does not limit the number of wells that can be drilled.

The AEUB also noted the landowners' discomfort that multiple pools on the same lands have the potential to require multiple wells to be drilled. However, normal operating practices include investigation of alternatives to limit both surface impacts and manage capital investments.

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35 *Supra* note 31.

8. AEUB PRE-HEARING MEETING DECISION 2003-088: *COMPTON PETROLEUM CORPORATION, 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)*[36]

Compton Petroleum Corporation (Compton) sought AEUB approval to drill six horizontal Level 2 critical sour gas wells with an anticipated maximum H_2S content of approximately 35.6 percent from an existing surface location about 1.1 km from the boundary of the city limits of Calgary. Compton also sought approval to reduce the emergency planning zone (EPZ) from 14.97 km to 4 km.

At the pre-hearing meeting the AEUB ruled that standing to participate in the hearing would be granted to parties within the 14.97 km EPZ. It also considered having two separate hearings, one into the application to reduce the EPZ to 4 km and the other into the well licence applications. The reason this arose was because Compton had carried out its public consultation program only with persons within the applied-for 4 km EPZ.

Intervenors argued that the AEUB was confronted with a potential procedural failure if the two issues were heard together and the AEUB refused to reduce the size of the EPZ. The AEUB ruled that it would nevertheless have only one hearing. It pointed out that should it refuse to reduce the EPZ to a 4 km radius then Compton would be obliged to revisit the scope of its public consultation.

9. AEUB DECISION 2003-101: *POLARIS RESOURCES LTD., APPLICATIONS FOR WELL LICENCE, SPECIAL GAS SPACING, COMPULSORY POOLING AND FLARING PERMIT, LIVINGSTONE FIELD*[37]

Polaris Resources Ltd. (Polaris) sought approval for the drilling and testing of a Level 3 critical sour gas well in the environmentally sensitive Whaleback area of Southern Alberta, as well as special gas well spacing, compulsory pooling and a flaring permit. The geological structures targeted by Polaris were the same as those previously targeted by Amoco Petroleum Canada Company Limited, which were the subject of a previously well-publicized and controversial AEUB hearing.[38]

Polaris believed that up to four wells might be needed to develop the reservoir. Some of the many intervenors suggested that Polaris' geological information was incomplete. The AEUB disagreed. It found that the targeted geological formations identified by Polaris were known to have hydrocarbon potential. The AEUB commented that the ultimate value of the well to the Alberta public was a critical element in the AEUB's determination of the public interest. However, it is interesting to note that the potential economic benefit of the well was unknown.

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36 (18 November 2003), AEUB Decision 2003-088 (pre-hearing meeting) (AEUB).

37 (16 December 2003), AEUB Decision 2003-101 (AEUB) [Decision 2003-101].

38 *In the Matter of an Exploratory Well Licence: Porcupine Hills-Whaleback Ridge Area; Amoco Canada Petroleum Company Ltd.* (September 1994), AEUB Decision 94-08 (AEUB).

In the hearing Polaris was severely criticized for its public consultation process. The AEUB in large part agreed with these criticisms. It felt that Polaris had mistaken the concept of notification with that of consultation. It said:

> Notification is often used by the petroleum industry as a means of informing the public about a proposed project via such means as open houses, fact sheets, and Web sites. Some companies believe that providing this information constitutes consultation. This is not the view of the Board. True consultation has the objective of obtaining specific public feedback on issues, concerns, and other matters that are open for discussion. Consultation allows the public to see how their involvement and input have been considered and addressed by the proponent. It is not apparent from the evidence that Polaris meaningfully considered input from the public to either explain its rationale or clarify or modify its applications. Rather, the Board heard statements from the interveners that Polaris repeatedly attempted to satisfy its own needs during consultation and provided little or no written response to the concerns voiced by area residents.[39]

However, the AEUB was also critical of members of the community who chose not to participate in the public consultation process. The AEUB noted that it could require companies to engage in meaningful consultation but it could not require members of the public to do so. The AEUB said that it was extremely unlikely to find that a public consultation process was incomplete or had failed if the public refused to participate.

A significant area of dispute concerned the environmental effects of the proposed well.

One of the environmental effects dealt with flaring. The AEUB felt Polaris complied with established dispersion modelling protocols, but felt that the evidence presented did not adequately deal with the chinook-induced air inversions common to the valley.

The AEUB had similar concerns with Polaris' plans regarding flood hazards, storage and containment, maintenance of roads from springs and surface run-off. In short, it felt Polaris had not been diligent in its selection of the well pad or mitigative measures. This is interesting because Alberta Environment had issued an approval under the *Environmental Protection and Enhancement Act*[40] allowing Polaris to reduce the standard 15 m setback for its well from a nearby water body.

A key area of dispute concerned the proximity of the proposed development to the Black Creek Heritage Rangeland. Although the well was on private land, it was a few hundred metres from the Rangeland. Polaris pointed to Government of Alberta policy documents stating that the Government intended to honour existing mineral commitments within legislated protected areas. Polaris argued that it was therefore reasonable for it to expect to drill the adjacent private lands.

The AEUB applied the principles in AEUB *Information Letter IL 93-09: Oil and Gas Developments Eastern Slopes (Southern Portion)*[41] that the operator must provide detailed environmental assessments so as to allow the AEUB to determine whether the project's

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39 Decision 2003-101, *supra* note 37 at 10.
40 R.S.A. 2000, c. E-12 [*EPEA*].
41 (13 December 1993), IL 93-09 (AEUB) [IL 93-09].

economic benefits and mitigation programs sufficiently outweighed any environmental costs. The AEUB found that it was unable to reach conclusions regarding ecosystem effects or appropriate mitigation measures. Further, Polaris had chosen not to submit a conceptual development plan for the project that included full field development and pipeline routing. The AEUB felt this did not meet the minimum requirements set out in *IL 93-09*. The AEUB concluded that it was not convinced that Polaris was able and prepared to take all actions necessary to mitigate any disturbance to the lands in question and to the Whaleback ecosystem as a whole.

With respect to public safety, the AEUB expressed serious reservations about Polaris' emergency response plan (ERP). It felt that the terrain and size of the area held significant barriers to effective emergency notification and evacuation, especially in winter when road access could be limited. The ERP did not address how the thousands of livestock in the area would be evacuated in an emergency. Polaris' telephone call-out system was also found inadequate given the lack of cell phone coverage in the area and the fact residents spent much of their working day in remote locations. Polaris' suggestion to have staff roving around to provide personal contact would not overcome these challenges. Hence, the AEUB found there was a high degree of uncertainty that evacuation in an emergency could be carried out effectively.

The AEUB also examined Polaris' financial and technical capabilities to properly drill the well. The AEUB, in assessing these issues, said:

> The proponent must have adequate expertise and person-power to implement project plans and the system of management. This management, technical, and operational expertise must not only include individuals from key disciplines but also sufficient numbers of supporting staff to be able to respond to technical problems, upsets, and emergencies effectively and on a timely basis. Further, the concept of adequate expertise must necessarily include provision for succession or backup in the event key individuals are unavailable or become incapacitated.
>
> The proponent must have sufficient financial resources to safely carry out projects according to design, respond to problems that may be encountered in project execution, implement effective emergency response programs, assume liabilities that may arise from emergencies, sustain safe operations, and satisfactorily reclaim projects following decommissioning. The financial capability must not only enable companies to respond to issues on a timely basis but also protect the larger public from having to assume unfunded liabilities that may arise from the proponent's projects.[42]

The AEUB felt that Polaris did not provide sufficient evidence that it had the protection programs and capabilities to safely drill and operate the proposed critical sour gas well. Similarly, it felt Polaris' plan to rely largely on contractors was questionable.

While the AEUB denied the well licence application, it emphasized that any future application would be considered on its merits and that in rejecting Polaris' well licence application it was not necessarily excluding future resource development in the environmentally important Whaleback areas.

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42 Decision 2003-101, *supra* note 37 at 32.

10. AEUB DECISION 2003-104: *RUBICON ENERGY CORPORATION, APPLICATION FOR A WELL LICENCE, GHOST PINE FIELD*[43]

Rubicon Energy Corporation (Rubicon) applied for a licence for a Level 1 sour oil well. A landowner who operated a recreational vehicle resort objected on the grounds that future expansion of the resort would be restricted because of the AEUB's setback requirements. They claimed that the local municipality was unlikely to allow the expansion if it was within the setback. They sought compensation of $10,000 per acre for loss of potential buyers and loss of revenue.

Rubicon calculated the emergency planning zone (EPZ) while drilling to be 991 m. During production, the EPZ would be only 100 m. Rubicon disputed the landowner's assertions that the well was really a Level 2 well and that their property would be devalued.

The AEUB accepted Rubicon's drilling release rate calculations. The landowner apparently produced no evidence to contradict Rubicon's release rate calculations. Therefore, the AEUB felt the appropriate setback was 100 m, even though it would have to be confirmed through production testing.

Finally, the AEUB made it clear that it has no jurisdiction to address matters of compensation.

11. AEUB DECISION 2003-107: *EXXONMOBIL CANADA LTD. AND EXXONMOBIL RESOURCES LTD., APPLICATIONS FOR WELL LICENCES, CROSSFIELD FIELD*[44]

ExxonMobil Canada Ltd. and ExxonMobil Resources Ltd. (collectively ExxonMobil) applied for well licences to drill two critical horizontal sour gas wells from a single well pad. Area residents objected.

The first objection concerned a memorandum of understanding between the AEUB, Alberta Environment and Alberta Agriculture, Food and Rural Development concerning animal health issues and complaints as outlined in AEUB *Information Letter IL 2002-04: Animal Health Complaints Involving the Petroleum Industry and Investigation Procedure.*[45] The AEUB decided it would not consider this issue as it related primarily to cattle marketing and compensation and was therefore outside of the AEUB's jurisdiction.

The second issue raised by the residents were concerns about a radioactive logging tool that was stuck in a nearby well. ExxonMobil advised that the tool had become stuck at approximately 2,400 m underground and 3,300 m horizontal from the well pad. It confirmed to the AEUB that the tool was properly abandoned in the wellbore in compliance with the requirements of the Canadian Nuclear Safety Commission. It felt there were no present or future risks to the public or the environment. The AEUB agreed. However, it said that

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43 (16 December 2003), AEUB Decision 2003-104 (AEUB).
44 (16 December 2003), AEUB Decision 2003-107 (AEUB).
45 (29 August 2002), IL 2002-04 (AEUB).

ExxonMobil could have been more proactive in its communication about the incident with the community.

Interestingly, about one and a half hours into the start of the hearing and apparently after most of the evidence had already been tendered, the Calgary Health Region (CHR) made a written request that the hearing be adjourned to give CHR time to prepare. The AEUB refused the request. It found that CHR had been notified of the project more than seven months earlier. Further, CHR's objection was filed three days late. Finally, CHR's request was made only in writing. The AEUB expected CHR would make such a request in person so the AEUB could clarify and better understand the reasons for the adjournment request.

12. JOINT PANEL REPORT AND AEUB DECISION 2004-005: *CANADIAN NATURAL RESOURCES LIMITED, APPLICATION FOR AN OIL SANDS MINE, BITUMEN EXTRACTION PLANT, AND BITUMEN UPGRADING PLANT IN THE FORT MCMURRAY AREA*[46]

Canadian Natural Resources Limited (CNRL) brought an application under the *Oil Sands Conservation Act*[47] for an oil sands mine, a bitumen extraction plant and upgrader and associated facilities for its $8.5 billion Horizon oil sands project in northern Alberta. The application was heard by a joint AEUB-Canadian Environmental Assessment Agency review panel (Joint Review Panel), who heard submissions from CNRL, other oil sands developers, First Nations, provincial and federal regulators, environmental groups and others.

The Joint Review Panel approved the application, albeit with 17 conditions relating to mining operations, conservation of the bitumen resource, management of the mine's waste rock tailings and long-term reclamation.

One of the many issues considered by the Joint Review Panel was whether CNRL's activities to depressure the basal aquifer could result in depressurization of the aquifer on the adjacent property of Deer Creek Energy Limited (Deer Creek) and thereby negatively impact Deer Creek's proposed Joslyn Creek steam-assisted gravity drainage (SAGD) project. Deer Creek argued that the depressurization of the basal aquifer could lead to a loss of pressure in the overlying bitumen zones rendering SAGD recovery uneconomical. Deer Creek argued the situation was analogous to the "gas-over-bitumen" issues and Deer Creek requested the AEUB impose a monitoring program. The Joint Review Panel agreed that the potential existed for CNRL's mining activities to impact SAGD recovery of the resource on Deer Creek's property. The Joint Review Panel therefore required careful monitoring and a requirement that mitigation steps be taken in the event impacts were identified.

A somewhat unique issue was also presented to the Joint Review Panel by a trapper who had constructed a residence approximately 300 m from CNRL's lease boundary. The Joint Review Panel expressed concern about residences being built within or near an oil sands mine. However, the Joint Review Panel admitted that it was not clear what regulatory authorities, if any, had jurisdiction to control or prohibit construction of residences in such

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46 (27 January 2004), AEUB Decision 2004-005 (AEUB).
47 R.S.A. 2000, c. O-7 [*OSCA*].

situations. The Joint Review Panel suggested that if there were regulatory authorities regulating such activities they should reconsider allowing residences in close proximity to oil sands mines.

13. AEUB DECISION 2004-006: *SOLEX GAS PROCESSING CORP., APPLICATION TO AMEND A GAS PROCESSING SCHEME AND FOR NATURAL GAS PIPELINES*[48]

Solex Gas Processing Corp. (Solex) applied to amend its gas processing licence for its Harmattan gas plant to allow sidestreaming of up to 12.7 $10^6m^3/d$ (450 MMcf/d) of sweet gas from the western system of NOVA Gas Transmission Limited (NGTL) for removal of natural gas liquids (NGLs). The plant had operated since 1961 but gas production had steadily declined for the last ten years. It was running at about 20 percent of its approved inlet capacity. Solex planned on contracting for NGL extraction rights with producers/shippers on NGTL upstream of Harmattan, thereby providing a competitive alternative to the Cochrane straddle plant, the only straddle plant on the NGTL western system. Burlington Resources Canada Partnership, Imperial Oil Resources and ExxonMobil supported the application. Each either had a working interest in or had their gas processed at the Harmattan plant.

Williams Energy (Canada), Inc. (Williams), BP Canada Energy Company (BP) and EnCana Corporation (EnCana) opposed the application. Williams owned the Cochrane plant downstream from Harmattan. BP and EnCana held interests in straddle plants elsewhere in Alberta and were concerned about their long-term viability.

The AEUB first reviewed its previous decision in *Strachan*.[49] There, the AEUB had approved an application by Gulf Canada Resources Limited to sidestream a relatively small amount of proprietary gas for NGL extraction on the condition that there was no identifiable impact on the viability of the straddle plant industry.

The AEUB acknowledged that once a producer or receipt point shipper put gas on the NGTL system, it no longer owned that particular gas but acquired in exchange a share of the common stream. The producer/shipper's entitlement from that point on was limited to re-acquiring its proportionate share of the common stream when gas was delivered at a delivery point. In other words, once a producer/shipper contracts with NGTL they give up any and all rights to the NGLs in that specific gas. The AEUB understood that the industry had developed a convention that straddle plants contract with shippers holding delivery capacity at border delivery points for NGL extraction prior to export.

The AEUB reaffirmed the right of producers to extract NGLs in the field. However, given the complexity related to gas ownership on the NGTL system and the fact that a number of key players had not participated in the proceeding, the AEUB was unwilling to extend NGL extraction through sidestreaming as sought by Solex unless it was in the public interest.

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48 (27 January 2004), AEUB Decision 2004-006 (AEUB) [Decision 2004-006]. Leave to appeal to the Alberta Court of Appeal was denied in *Solex Gas Processing Corp. v. Alberta (Energy and Utilities Board)* (2004), 361 A.R. 232.

49 *Gulf Canada Resources Limited: Strachan Gas Plant Approval Amendment: NGTL Sidestreaming Application* (26 September 1996), AEUB Decision D 96-07 (AEUB) [*Strachan*].

In considering the public interest, the AEUB reviewed the current contracting convention and impact on the natural gas markets. It concluded that approval of Solex's application would affect current practices and markets, and it was unwilling to consider such changes in the absence of full consultation with stakeholders, not all of whom participated in the hearing. Further, the AEUB felt that Solex's proposed tracking system to ensure that a producer did not sidestream more NGLs than its fair share had been developed without consultation of parties who might be affected.

The AEUB noted that the proposal would result in incremental ethane production. However, this benefit had to be assessed with the costs of the extra energy needed to realize the incremental volumes.

As for the impacts to the existing straddle plant owners, the AEUB noted that they do not have a pre-emptive right to be protected from upstream NGL recovery. However, it felt that the existing straddle plants should not be jeopardized by a proliferation of upstream facilities in the absence of compelling public interest reasons. It said:

> The Board agrees with the interveners opposed to the application that the ability to extract significant NGL from the NGTL stream could be an incentive for plants with unused capacity other than Harmattan to pursue sidestreaming upstream of the straddle plants and upstream of each other. The Board acknowledges that there are a number of plants with unused processing capacity. The Board views that while the enhanced NGL production at any one plant may well be the basis for an economic project for the proponent, the overall effect on the Alberta NGL supply system could be significantly reduced energy efficiency, increased NGL supply costs, and lower overall NGL recoveries. Energy and cost inefficiencies, in particular, would result if residue gas from sidestream operations were returned to the NGTL system upstream of straddle plants that subsequently reprocess the leaner gas. Reduced NGL supply could result if sidestreaming of partial NGTL flows ultimately causes downstream straddle plants to shut down or bypass lean gas, both of which would result in increased volumes of NGL leaving the province.[50]

The AEUB concluded that Solex had failed to demonstrate that its proposal was in the public interest, that it might have an adverse impact on the straddle plant system and could require change to contracting conventions with system-wide implications. The AEUB denied Solex's application.

14. JOINT PANEL REPORT AND AEUB DECISION 2004-009: *SHELL CANADA LIMITED, APPLICATIONS FOR AN OIL SANDS MINE, BITUMEN EXTRACTION PLANT, COGENERATION PLANT, AND WATER PIPELINE IN THE FORT MCMURRAY AREA*[51]

Shell Canada Limited (Shell) applied under the *OSCA*[52] for an approval of its proposed Jackpine oil sands truck and shovel mine and a bitumen extraction facility, as well as a cogeneration plant under the *Hydro and Electric Energy Act*[53] and a freshwater pipeline

50 Decision 2004-006, *supra* note 48 at 20.
51 (5 February 2004), AEUB Decision 2004-009 (AEUB).
52 *Supra* note 47.
53 R.S.A. 2000, c. H-16.

under the *Pipeline Act*.[54] The applications were heard by a joint AEUB-Canadian Environmental Assessment Agency panel (Joint Review Panel).

A number of environmental and First Nations groups advised the Joint Review Panel that agreements had been reached with Shell. Each asked the AEUB to include with its approval the matters described in the agreements. However, the Joint Review Panel determined that the agreements would not form part of the AEUB approval but nevertheless stated that it expected Shell to meet its commitments under the agreements throughout the life of the project.

One area of concern raised by intervenors was the predicted impact of the project on the quantity of water in the Athabasca River. No one had yet fully determined what the appropriate instream flow need (IFN) was for the river. Some intervenors argued that Shell should not receive any water diversion licences under the *Water Act*[55] until an IFN was established. However, the Joint Review Panel noted that an IFN was being developed and that Alberta Environment could amend terms and conditions of *Water Act* licences once the IFN was established. The Joint Review Panel felt there was no need to defer the project.

One environmental objector pointed out that Shell had not taken into account the effect of climate change on the project. However, the Joint Review Panel noted that the impact of climate change on the project was not part of the terms of reference of the environmental impact assessment. The Joint Review Panel commented that when the federal government finalized its climate change guidelines, all subsequent environmental impact assessments would have to follow those guidelines.

III. LEGISLATIVE DEVELOPMENTS

A. FEDERAL LEGISLATION

1. *AN ACT TO AMEND THE CANADIAN ENVIRONMENTAL ASSESSMENT ACT*[56]

This *Act* was proclaimed in force as of 30 October 2003. These amendments to the *CEAA* were the result of the statutory five-year review of the *CEAA*, which commenced at the end of 1999. This amendment act was formerly Bill 9, which was discussed in last year's article.[57]

Significant changes made to the *CEAA* include:

- adding a federal environmental assessment coordinator to assist departments and agencies in conducting environmental assessments and to monitor their effectiveness;
- elimination of the possibility of referring a project to a review panel following a comprehensive study assessment;

54 R.S.A. 2000, c. P-15.
55 R.S.A. 2000, c. W-3.
56 S.C. 2003, c. 9 [*CEAA*].
57 Gordon M. Nettleton, "Recent Regulatory and Legislative Developments of Interest to Oil and Gas Lawyers" (2004) 42 Alta. L. Rev. 247 at 283.

- creation of the Canadian Environmental Assessment Registry on the Internet to allow easy public access to environmental assessment information on specific projects;
- extending environmental assessment obligations to certain Crown corporations and federally funded projects on reserve lands;
- a stronger role for the Canadian Environmental Assessment Agency in promoting and monitoring compliance with the *CEAA*;
- increased follow-up of assessments to ensure that sound mitigation measures are put in place;
- extension of participant funding to comprehensive study assessments in addition to review panels; and
- the formal recognition of Aboriginal traditional knowledge in the assessment process.

One of the purposes of the amendments was to focus the environmental assessment process on those projects that are more likely to have significant adverse environmental effects and move away from those with insignificant impacts. To this end, class screening reports can now be utilized to replace project-specific assessments for projects that are considered to be routine with known environmental effects.

2. *SPECIES AT RISK ACT*[58]

This *Act* came into effect in multiple phases. As of 1 June 2004 it is now an offence to kill, harm, harass or capture an individual of a listed species or to damage or destroy the residence of certain listed species. The listed species include plants, birds, fish and animals. *SARA* currently applies only to federal lands, including most of the lands in the three territories, except in the case of listed aquatic species and for birds covered by the *Migratory Birds Convention Act, 1994*.[59] All projects which are subject to a federal environmental assessment must now take into account the project's effects on the listed species and their critical habitants.

3. *INCLUSION LIST REGULATIONS AMENDMENT*,[60] *LAW LIST REGULATIONS AMENDMENT*,[61] *COMPREHENSIVE STUDY REGULATIONS AMENDMENT*[62]

Effective 28 July 2003 several regulations were amended to apply the federal environmental assessment program under the *CEAA* to certain East Coast hydrocarbon exploration activities. Exploration activities such as seismic and drilling in offshore areas will now be subject to the same environmental assessment processes as production activities. The *Comprehensive Study Regulations*[63] were amended to require that new offshore exploratory drilling projects undergo a comprehensive study assessment.

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58 *Supra* note 28.
59 S.C. 1994, c. 22.
60 S.O.R./2003-280.
61 S.O.R./2003-281.
62 S.O.R./2003-282.
63 S.O.R./94-638.

B. ALBERTA LEGISLATION

The scope of legislative change in Alberta from April 2003 through March 2004 was not broad, with no material changes to the *Energy Resources Conservation Act*,[64] *Alberta Energy and Utilities Board Act*,[65] *Oil And Gas Conservation Act*,[66] *Oil Sands Conservation Act*[67] or *Pipeline Act*.[68]

1. *PUBLIC LANDS AMENDMENT ACT, 2003*[69]

This *Act*, which partially came into force on 4 December 2003, amends the *Public Lands Act*.[70] Important amendments include an expansion of the powers of the Lieutenant Governor in Council to make regulations limiting or restricting areas of the province in respect of which the Minister may issue certain kinds of dispositions. Changes include, among other things, a prohibition on blocking, disrupting, hindering, impeding, interfering with or otherwise obstructing free access or passage on a highway, road or trail on public land without the Minister's authorization. Further, it is now unlawful for any person to directly or indirectly induce or attempt to induce another person to provide money or other consideration for the purpose of gaining access to or use of a public road unless the person holds a disposition and is entitled at law to request and receive money or other consideration. Similarly, it is unlawful to pay someone money or other consideration in order to gain access or use of a public road unless the person receiving it holds a disposition and is entitled at law to charge for the access or use. Police officials now have powers to remove and seize barriers or other obstructions. Also, a person who is prevented lawful access and use may apply to the Court of Queen's Bench for an order allowing access. The application may be made *ex parte* for an order, which is effective for up to seven days.

2. *MINES AND MINERALS AMENDMENT ACT, 2003*[71]

Amendments made to the *Mines and Minerals Act*[72] include:

- enabling the Minister to prescribe rules, directives, codes, standards and guidelines in respect of the conduct of exploration and related matters and adopt such codes by regulation;
- enabling the Minister to conduct investigations or inspections, issue stop orders where the *Mines and Minerals Act*, regulations, codes or exploration licences, permits or approvals are not being complied with; and
- authorizing the Minister to suspend a licence if no exploration has been conducted under the licence for a period of two years or more.

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64 *Supra* note 20.
65 *Supra* note 23.
66 *Supra* note 21.
67 *Supra* note 47.
68 *Supra* note 54.
69 S.A. 2003, c. 46.
70 R.S.A. 2000, c. P-40.
71 S.A. 2003, c. 28.
72 R.S.A. 2000, c. M-17.

3. *PIPELINE REGULATION AMENDMENT*[73]

This regulation amends the *Pipeline Regulation*[74] and reflects the release of the AEUB's *Guide 71: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry.*[75] Licensees are now required, pursuant to s. 50 of the *Pipeline Regulation*, to prepare either a Corporate Emergency Response Plan or a Specific Emergency Response Plan (depending on the nature of the pipeline). Specific Emergency Response Plans must be submitted to the AEUB for approval and training exercises. Reports and spill response contingency plans may also now be required.

4. *AGRICULTURAL DISPOSITIONS STATUTES AMENDMENT ACT, 2003*[76]

This amendment act provides an appeal process for resource companies who want to access land for exploration purposes. In the past, once a leaseholder refused access for exploration, the company had no appeal. Under this amendment act, if a leaseholder refuses entry, a new dispute resolution process with the Surface Rights Board may be utilized and a right of entry order to explore on a grazing lease or farm development lease may be granted. The *Exploration Regulation*[77] under the *Mines and Minerals Act*[78] has also been amended to reflect these changes.

5. *OIL SANDS CONSERVATION REGULATION AMENDMENT*[79]

The *Oil Sands Conservation Regulation*[80] has been amended to provide that operators of any "in situ schemes" must report the progress, performance and efficacy of the scheme in accordance with the AEUB's *Interim Directive ID 2002-03: Performance Presentations for In Situ Oil Sands Schemes*[81] and amendments thereto.

6. *CO_2 PROJECTS ROYALTY CREDIT REGULATION*[82]

This new regulation under the *Mines and Minerals Act*[83] provides for a new royalty reduction program that was implemented to promote the development of a carbon dioxide enhanced oil and gas recovery industry in Alberta. A maximum of $15 million will be provided over five years in the form of oil and natural gas royalty credits to offset up to 30 percent of companies' approved costs in approved CO_2 projects.

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73 Alta. Reg. 192/2003.
74 Alta. Reg. 122/1987, as am.
75 June 2003 (AEUB) [*Guide 71*].
76 S.A. 2003, c. 11.
77 Alta. Reg. 214/1998, as am.
78 *Supra* note 72.
79 Alta. Reg. 191/2003.
80 *Supra* note 33.
81 (20 December 2002), ID 2002-03 (AEUB).
82 Alta. Reg. 120/2003.
83 *Supra* note 72.

7. *OIL AND GAS CONSERVATION REGULATIONS AMENDMENTS*[84]

Part Eight of the *Oil and Gas Conservation Regulations*[85] was amended to reflect the AEUB's release of *Guide 71: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry.*[86] Part Fifteen was amended to provide that specified applications (such as rateable take applications, common carrier applications, enhanced recovery applications and special spacing applications) must be made in accordance with AEUB *Guide 65: Resource Applications for Conventional Oil and Gas Reservoirs.*[87]

8. *MINERAL RIGHTS COMPENSATION REGULATION*[88]

This regulation repealed and replaced the *Mineral Rights Compensation Regulation, 1978.*[89] This regulation provides for compensation to a lessee in the event that the Minister decides that any, or any further, exploration for or development of a mineral in the location of a lessee's agreement is not in the public interest or the lessee's agreement contains a misdescription of zone.

9. *ENERGY STATUTES AMENDMENT ACT, 2003*[90]

This *Act* amends two energy statutes, the *Freehold Mineral Rights Tax Act*[91] and the *Mines and Minerals Act*,[92] by providing that the *Limitations Act*[93] does not apply to certain claims under these acts. Other amendments to the *Mines and Minerals Act* include:

- a revision of those provisions dealing with calculations and recalculations of offset compensation and royalty proceeds;
- a revision of those provisions pertaining to compensation for unauthorized takings; and
- a provision specifying that all agreements granting rights in respect of oil sands that are issued on or after 1 January 2001 grant the right to solution gas.

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84 Alta. Reg. 190/2003, Alta. Reg. 32/2003.
85 *Supra* note 31.
86 *Supra* note 75.
87 June 2000, revised June 2003 (AEUB) [*Guide 65*].
88 Alta. Reg. 317/2003.
89 Alta. Reg. 161/78.
90 S.A. 2003, c. 18.
91 R.S.A. 2000, c. F-26.
92 *Supra* note 72.
93 R.S.A. 2000, c. L-12.

C. BRITISH COLUMBIA LEGISLATION

1. *OIL AND GAS COMMISSION ACT AMENDMENTS*

The *Oil and Gas Commission Act*[94] had several consequential amendments. The majority of these amendments affected the definitions in s. 1. Sections 19-21 were repealed by the *Utilities Commission Amendment Act, 2003.*[95]

The *Energy and Mines Statutes Amendment Act, 2002*[96] made the most extensive consequential amendments to the *Oil and Gas Commission Act*. It changed the requirements to establish the Oil and Gas Commission (OGC) as a corporation, added a section providing for the OGC to be an agent of the government, changed the powers of the OGC to pass resolutions to direct its affairs, and added sections providing for the powers of the commissioner and on general development permits.

2. *PETROLEUM AND NATURAL GAS ACT AMENDMENTS*

The *Petroleum and Natural Gas Act*[97] also had various amendments to its definition section. The amendments also affected the number of individuals on the Mediation and Arbitration Board.

Among other changes, s. 84.1 now specifies that the *Waste Management Act*[98] requirements are to be met with an application for a certificate of restoration with respect to a well, test hole or production facility. Section 84 regarding Certificates of Restoration has been expanded. It now includes provisions allowing the OGC to certify that the well, test hole or production facility was abandoned in accordance with the regulations, and that a Certificate of Restoration does not absolve the holder of a well authorization, a test hole authorization or the owner of a production facility from their obligation to abandon it in accordance with the regulations.

3. *PIPELINE ACT AMENDMENTS*

The *Pipeline Act*[99] had minor amendments to its definitions, sections and fees to be paid by companies having dealings with the Ministry of Transportation and Highways.

4. *COALBED GAS ACT*[100]

On 10 April 2003 the *Coalbed Gas Act* came into force.

94 S.B.C. 1998, c. 39.
95 S.B.C. 2003, c. 46.
96 S.B.C. 2002, c. 26.
97 R.S.B.C. 1996, c. 361.
98 R.S.B.C. 1996, c. 118.
99 R.S.B.C. 1996, c. 364.
100 S.B.C. 2003, c. 18.

5. *OIL AND GAS COMMISSION REGULATION*[101]

This regulation amended the *Geophysical Exploration Regulation*[102] so that approval for projects must now be in the form required by the OGC. Further, OGC employees can in certain instances exempt operators from submitting a revised application to alter a geophysical exploration program from that described in the original application.

This regulation also amended certain procedural matters set out in the *Drilling and Production Regulation*.[103]

IV. POLICIES, DIRECTIVES AND GUIDELINES

A. NATIONAL ENERGY BOARD

1. *APPROPRIATE DISPUTE RESOLUTION: GUIDELINES — JULY 2003*[104]

Since 2002, the NEB has been developing an Appropriate Dispute Resolution (ADR) program. ADR is viewed as a collection of tools and techniques that can be used to reach resolution on an issue in lieu of reliance on the NEB's traditional regulatory process. On 18 July 2003 the NEB issued its guidelines for its ADR program.

The various options under the NEB's ADR program include negotiation, facilitation, workshops and mediation. The NEB's goal was to ensure that there were fair and efficient processes in place in respect of these alternatives to the litigated hearing approach. While the ADR processes are voluntary, the NEB will be proactive in attempting to identify situations where ADR techniques may be effective. A facilitator will usually be used to assist in establishing an appropriate ADR procedure to be utilized in respect of a particular issue. A NEB staff member may act as the facilitator and the NEB staff could participate in any ADR session should the parties so desire. Where an agreement is reached, the NEB will still have to ensure that the agreement is consistent with the *NEB Act*[105] and all other legislation and to take into account public interest considerations when deciding whether to approve an agreement.

The NEB has employed conflict management specialists who will assist parties in the ADR process. The NEB believes that the greatest potential for ADR will be in resolving land issues and toll and tariff issues. The NEB also sees the potential for using various ADR techniques in respect of technical conferences within a regulatory process and in the development of new regulations and guidelines.

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101 B.C. Reg. 257/2003.
102 B.C. Reg. 361/98.
103 B.C. Reg. 362/98.
104 NEB, *Appropriate Dispute Resolution: Guidelines — July 2003*, (July 2003) (NEB).
105 *Supra* note 9.

2. *GUIDANCE NOTES FOR THE NATIONAL ENERGY BOARD PROCESSING PLANT REGULATIONS*[106]

The NEB has published a detailed set of guidance notes in respect of the *National Energy Board Processing Plant Regulations.*[107] These regulations apply to processing plants that are subject to NEB jurisdiction. The guidance notes were prepared by the NEB to provide voluntary guidance that will assist companies in complying with these regulations. As with the *Onshore Pipeline Regulations, 1999,*[108] these are goal-oriented regulations.

3. *GUIDANCE NOTES FOR APPLICANTS, APPLICATIONS FOR DECLARATION OF SIGNIFICANT DISCOVERY AND COMMERCIAL DISCOVERY — 1997*[109]

In addition to its *NEB Act* responsibilities, the NEB has regulatory responsibilities under provisions of the *Canada Petroleum Resources Act*[110] in respect of certain frontier lands, particularly in the northern regions of Canada. With increasing activity north of the sixtieth parallel, the NEB is receiving more applications for declarations of a significant discovery and of a commercial discovery under the *CPR Act.* In 1997 a set of guidelines for these types of applications were issued. On 17 November 2003, the NEB revised s. 4 of these guidelines to set out the NEB's current procedure for processing these applications. The NEB will now issue a notice of an application, which will allow persons other than the applicant to seek status as a Directly Affected Person (DAP). The applicant will have the right to challenge any person's claim that it should be a DAP and the NEB will, on a case by case basis, decide who, if anyone beyond the applicant, would be directly affected by the NEB's decision, and who will be given DAP status.

4. *NATIONAL ENERGY BOARD PRE-APPLICATION MEETINGS GUIDANCE NOTES*[111]

During the fall of 2003, the NEB undertook a review of its existing guidance notes for pre-application meetings. As a result of the comments it received, the NEB has issued new guidance notes on this matter. The new guidance notes set out the procedure to be followed by any potential applicant who wishes to meet with NEB staff prior to the filing of an application. While pre-application meetings are not required, they can be useful to a potential applicant to gain a better understanding of the application process and the NEB's regulatory requirements. In any meeting the *Code of Conduct for NEB Employees*[112] and natural justice principles must continue to be respected. These guidance notes set out the proper procedure for requesting a meeting, the content of such meetings and the participants who may be involved.

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106 (28 July 2003) (NEB).
107 S.O.R./2003-39.
108 S.O.R./99-294.
109 (17 November 2003) (NEB).
110 R.S.C. 1985, c. 36 [*CPR Act*].
111 (26 February 2004) (NEB).
112 NEB, *Code of Conduct for NEB Employees* (effective April 2002), online: NEB <www.neb-one.gc.ca/aboutus/codeofconduct_e.htm>.

5. *FILING MANUAL*[113]

In late 2002, the NEB initiated a review of its *Guidelines for Filing Requirements*,[114] which were first published in 1995. After a number of rounds of consultation with the industry and the public, the NEB completed this process when it recently issued its *Filing Manual*. The *Filing Manual* replaces the *Guidelines for Filing Requirements* in its entirety. The *Filing Manual* contains a comprehensive set of guidelines setting out what is required in respect of most of the types of applications that the NEB may consider under the *NEB Act*. By clearly setting out the material that the NEB requires for each application, the NEB hopes that the NEB's expectations can be clearly understood and that the regulatory application requirements will be applied uniformly to all applicants. All applications to the NEB filed after 29 April 2004 will be required to comply with the *Filing Manual*.

While it is beyond the scope of this article to go into detail about each of the changes in the *Filing Manual*, it is fair to say that there is a increased emphasis on requiring consultation to take place prior to any application being filed. This consultation relates not only to local residents and land users, government authorities and Aboriginal groups, but also to commercial third parties. This consultation process now extends beyond applications for approval of physical projects and applies to tolls and tariff applications, import/export authorizations, change-in-ownership authorizations and plan, profile and book-of-reference applications.

B. ALBERTA ENERGY AND UTILITIES BOARD

1. *GUIDE 71: EMERGENCY PREPAREDNESS AND RESPONSE REQUIREMENTS FOR THE UPSTREAM PETROLEUM INDUSTRY*[115]

One of the recommendations of the Provincial Advisory Committee on Public Safety and Sour Gas was that the AEUB develop clear and concise guidelines for emergency response plan development. Accordingly, in June 2003 the AEUB released *Guide 71* and rescinded, in whole or in part, nine existing AEUB Interim Directives and Information Letters.[116]

Guide 71 provides the minimum AEUB emergency preparedness and response requirements for the upstream petroleum industry and adopts the current edition of CSA Standard CAN/CSA Z-731. It is the responsibility of the licensee (including approval and

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113 (29 April 2004) (NEB).

114 (1995) (NEB).

115 *Supra* note 75.

116 *Interim Directive ID-OG 76-2: Emergency Procedure Plans for Sour Gas Facilities*; *Interim Directive ID 90-1: Completion and Servicing of Sour Wells, Section 3 — Emergency Response Plans*; *Interim Directive ID 91-02: Corporate-Level Emergency Response Plans*; *Interim Directive ID 97-06: Sour Well Licensing and Drilling Response Plan*; *Informational Letter IL 87-08: Emergency Response Plans for Sour Gas Facilities*; *Informational Letter IL 88-17: Ignition Equipment for Drilling Critical Sour Wells*; *Informational Letter IL 89-15: Evacuation and Ignition for Sour Wells*; *Informational Letter IL 90-17: Emergency Procedure Plans for Sour Gas Facilities — Biennial Meetings*; and *Informational Letter IL 99-01: Spill Equipment Deployment, Training Exercise Approvals and Report Summaries*.

permit holders) to determine when an emergency response plan (ERP) is required and the type of plan required.

Guide 71 details common emergency preparedness and response requirements that apply to any hazard related to upstream petroleum operations and sets out additional requirements specific to sour wells, sour protection facilities and associated gathering systems, high vapour pressure pipelines, spills of hydrocarbons and produced water, and hydrocarbon storage in caverns.

An important part of *Guide 71* is that it describes the methodology for upstream oil and gas proponents to determine the size of an emergency planning zone (EPZ) around a well, pipeline or facility where immediate response actions are required in the event of an emergency. The scope of the EPZ is important for numerous reasons, including that it sets, in part, the scope of the necessary public consultation and local government notification and consultation requirements required under *Guide 56: Energy Development Applications and Schedules*.[117]

The AEUB's expectations for conducting public involvement programs for an ERP are also outlined, as are the requirements for corporate-level ERPs as required by s. 8.002 of the *OGCR*[118] and s. 50.1 of the *Pipeline Act*.[119]

Guide 71 is more than a consolidation of previous AEUB requirements with respect to emergency response planning. New requirements, among others, include:

- requirements that licensees of high vapour pressure pipelines and licensees of hydrocarbon storage caverns prepare and submit ERPs to the AEUB for approval;
- requirements that public and local government involvement in emergency planning occur prior to any transfers of wells, pipelines and facilities that require specific ERPs;
- requirements that corporate-level ERPs meet the *Guide 71* requirements; and
- requirements that licensees of gathering systems associated with a facility enter into a cooperative mutual aid agreement with the facility operator to ensure appropriate emergency response.

2. *GENERAL BULLETIN GB 2003-16: PROPOSED CONSERVATION POLICY AFFECTING GAS PRODUCTION IN ATHABASCA WABISKAW-MCMURRAY OIL SANDS AREAS*[120]

Since 1997, the AEUB has consulted with industry, held public hearings and reviewed evidence regarding the potential effects of natural gas production on the recovery of bitumen in the geological strata of the Wabiskaw-McMurray formation in the Athabasca Oil Sands area. In that time frame, the AEUB has conducted three major inquiries into this natural

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117 October 2003 (AEUB) [*Guide 56*].
118 *Supra* note 31.
119 *Supra* note 54.
120 (3 June 2003), GB 2003-16 (AEUB) [*General Bulletin GB 2003-16*].

gas/bitumen matter: a general inquiry, *Gas/Bitumen Production in the Oil Sands Areas, March 1998*;[121] the *Surmont* decision, March 2000;[122] and the *Chard-Leismer* decision, March 2003.[123]

On 3 June 2003, the AEUB released *General Bulletin GB 2003-16*, which set out further steps to review and revise its conservation policy respecting gas production from the Wabiskaw-McMurray formation in the Athabasca Oil Sands area. Included as an attachment to this *General Bulletin* was a *Proposed Conservation Policy*. The AEUB concluded that gas production from some wells completed prior to July 1998 presented an unacceptable risk to future thermal bitumen recovery, and that immediate action was required. Therefore, it required an 1 August 2003 shut-in of all Wabiskaw-McMurray gas production from wells within a revised Wabiskaw-McMurray application area. The revised Wabiskaw-McMurray application area was created by amending the description of the Wabiskaw-McMurray deposit in the appendix to *Interim Directive ID 99-1: Gas/Bitumen Production in Oil Sands Areas — Applications, Notifications, and Drilling Requirements*.[124] The AEUB also announced that it would complete a detailed review of shut-in gas production within the new application area to allow the production of nonassociated gas.

The AEUB noted that the thickest bitumen within the Athabasca Wabiskaw-McMurray deposit is generally located in a north-south trending channel complex along the eastern portion of the Athabasca Oil Sands area. This bitumen trend contains all existing and proposed SAGD projects in the Athabasca Oil Sands area, as well as the areas included in the Surmont and Chard/Leismer hearings. The AEUB has defined an area of concern that encompassed this thick bitumen trend and indicated that the entire area has similarities with respect to geological environment, bitumen thickness encountered and general gas production history. This area is coincident with channel sequences having thicknesses generally exceeding ten metres and over 6 weight percent bitumen (approximately 50 percent saturation). Outside the area, the Wabiskaw-McMurray deposit typically becomes thinner, channel sequences are less predominant and the bitumen is generally not believed to be exploitable using SAGD or reasonably foreseeable thermal technologies.

There are approximately 500 billion barrels of bitumen existing in the Wabiskaw-McMurray deposit. Using a 20 percent recovery factor, this results in recoverable reserves in the order of 100 billion barrels. The AEUB put this in context by pointing out that this volume is seven times greater than all the conventional oil produced to date, or 60 times the remaining conventional oil reserves in Alberta. On the other hand, there is about one tcf of remaining gas reserves in the Wabiskaw-McMurray formation, about 1 percent of the provincial total. This gas has an energy equivalence of 175 million barrels of bitumen, or in other terms, the energy content of the recoverable crude bitumen reserves at risk is about 600 times larger than the energy content of the proposed shut-in Wabiskaw-McMurray gas production.

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121 EUB Inquiry Gas/Bitumen Production Oil Sand Areas, March 1998.

122 *Gulf Canada Resources Limited, Request for the Shut-In of Associated Gas, Surmount Area* (March 2000), AEUB Decision 2000-22 (AEUB)..

123 *Chard Area and Leismer Field, Athabasca Oil Sands Area, Applications for the Production and Shut-In of Gas* (18 March 2003), AEUB Decision 2003-023 (AEUB).

124 (3 February 1999), ID 99-1 (AEUB).

The AEUB noted that the geology of the Wabiskaw-McMurray is complex. For the AEUB to determine whether gas is associated with bitumen requires an understanding of the local geology in the context of a regional geological framework. This geological work, initiated in the Chard/Leismer area, was not complete for the remainder of the area and would be a priority for the AEUB. The AEUB believes that applications in this area need to be deferred to facilitate early completion of the study. This provides for the most efficient and consistent processing of subsequent applications and would result in the earliest identification of nonassociated gas.

3. *GENERAL BULLETIN GB 2003-21: COMMINGLING OF PRODUCTION FROM TWO OR MORE POOLS IN THE WELLBORE AMENDED GUIDE 65 PRESENTS PROCESSES FOR OBTAINING EUB APPROVAL*[125]

In this *General Bulletin*, the AEUB announced that well licensees have two options to obtain approval to commingle production from two or more pools in a single wellbore. The first option is for the licensee to file a notification form with the AEUB and all potentially affected parties. To determine if notification is appropriate, licensees have to walk through the decision tree in Appendix H of *Guide 65*.[126] If the well meets the requirements, the licensee can then commingle without AEUB approval provided that the AEUB is notified within 30 days. The notification process cannot be used for commingling different types of fluids from separate pools.

The second option is for the licensee to obtain an order from the AEUB approving the commingling following the filing of an application filed in accordance with *Guide 65*.

4. *GENERAL BULLETIN GB 2003-28: BITUMEN CONSERVATION REQUIREMENTS ATHABASCA WABISKAW-MCMURRAY*[127]

In response to *GB 2003-12*[128] and *GB 2003-16*,[129] and consultative meetings with industry, the AEUB announced a three-phase approach to identifying and curtailing gas production associated with potentially recoverable bitumen.

In Phase 1, effective 1 September 2003, the AEUB ordered the interim shut-in of Wabiskaw-McMurray gas production in the area of concern, unless operators filed a temporary exemption with the AEUB. Temporary exemptions were provided for wells where operators had evidence that natural gas extraction does not affect the potential extraction of bitumen.

In Phase 2, exempted wells contested by the AEUB or affected parties were addressed on an interim basis through an expedited AEUB process. If contested, the gas operator has to

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125 (23 June 2003), GB 2003-21 (AEUB).

126 *Supra* note 87.

127 (22 July 2003), GB 2003-28 (AEUB).

128 AEUB, *General Bulletin GB 2003-12: Gas Production in Oil Sands Areas* (3 April 2003), GB 2003-12 (AEUB) [*GB 2003-12*].

129 AEUB, *General Bulletin GB 2003-16: Proposed Conservation Policy Affecting Gas Production in Athabasca Wabiskaw-McMurray Oil Sands Areas* (3 June 2003), GB 2003-16 (AEUB) [*GB 2003-16*].

produce evidence in support of the exemption. If an operator fails to produce the evidence, the producing zone would be subject to immediate interim shut-in, and the AEUB could audit that operator's remaining exempted wells. Evidence of further non-compliance would invoke the AEUB's general enforcement process.

In this third phase, upon completion of all or a portion of the regional geological study, the AEUB will notify affected parties of its intention to continue or vary a well's gas production status. If an affected party objects, an AEUB hearing will be held regarding the matter.

The AEUB released a regional geological study on 2 January 2004. The study identified where natural gas is in contact with bitumen in the Wabiskaw-McMurray areas. The study does not specifically identify individual gas wells that may be subject to permanent shut-in.

5. *GENERAL BULLETIN GB 2003-22: CLARIFICATION OF ENERGY APPLICATION PROCESS: WHEN MAY AN APPLICANT REQUEST A HEARING WITH THE ALBERTA ENERGY AND UTILITIES BOARD?*[130]

In this *General Bulletin* the AEUB advises that an applicant may request a hearing at any time but the AEUB will not make a disposition of an application until the application is complete. All of the audit and technical information required by *Guide 56*[131] must be provided for an application to be considered complete.

Further, applicants are required to address all questions and objections from potentially affected parties, although this does not mean that they are required to resolve the issues. Applicants must document that they have made serious attempts to notify and consult all potentially affected parties.

6. *GUIDE 20: WELL ABANDONMENT GUIDE*[132]

The *OGCR*,[133] requires well licensees to abandon wells in accordance with *Guide 20: Well Abandonment Guide*. A new *Guide 20* was released by the AEUB on 1 August 2003. The changes to the previous *Guide 20* include six technical changes to abandonment procedures and clarifications to the procedures for abandoning oil sands evaluation and test holes and single-zone horizontal wells.

7. *INTERIM DIRECTIVE ID 2003-02: LARGE UPSTREAM OIL AND GAS FACILITIES — INTERIM TRANSFER REVIEW PROCESS*[134]

Sulphur recovery plants, stand-alone straddle plants and certain *in situ* oil sands processing plants historically have not been included within the AEUB's Licensee Liability Rating (LLR) program. The AEUB has now introduced a transfer review process to limit the risks

130 (24 June 2003), GB 2003-22 (AEUB).
131 *Supra* note 117.
132 August 2003 (AEUB) [*Guide 20*].
133 *Supra* note 31.
134 (19 August 2003), ID 2003-02 (AEUB).

of facilities having potentially large abandonment and/or reclamation liabilities being transferred to a party that might not be capable of managing such liabilities. The process involves an assessment of the deemed asset and deemed liability values of the facility. The deemed liabilities are to be calculated by a site-specific liability assessment acceptable to the AEUB. The deemed assets are calculated using an average daily facility volume multiplied by the facility's netback over three years. A party proposing the transfer of any of this type of a facility has to provide the AEUB with the information required to allow the calculations to be undertaken.

8. *GUIDE 56: ENERGY DEVELOPMENT APPLICATIONS AND SCHEDULES*[135]

In June 2003 the AEUB announced a new edition of *Guide 56: Energy Development Applications and Schedules* to become effective 1 October 2003. When the new *Guide 56* was released in September 2003, it included a number of other changes and revisions due to feedback from stakeholders.

In addition to rescinding a number of AEUB documents,[136] the AEUB clarified, among other things, participant involvement requirements, routine and non-routine application processes and mineral lease continuations. Further, licences now expire 12 months after issuance if not acted upon, criteria is provided for multiwell facilities and a number of schedules were reformatted.

As of 1 October 2003, all applications had to be compliant with the new *Guide 56*. However, the AEUB allowed a "transition period" until 31 March 2004 for applicants to become familiar with the new requirements. The transition period included a reduced enforcement program with respect to *Guide 56* violations.

9. *DIRECTIVE 001: REQUIREMENTS FOR SITE-SPECIFIC LIABILITY ASSESSMENTS IN SUPPORT OF THE EUB'S LIABILITY MANAGEMENT PROGRAMS*[137]

Directive 001 sets out the AEUB's requirements for site-specific liability assessments. A "liability assessment" is an assessment conducted by a licensee or approval holder to estimate the cost to suspend, abandon and reclaim a site. The approach and documentation specified in *Directive 001* are introduced to improve the consistency and accuracy of liability cost estimates submitted to the AEUB. They do not modify requirements concerning how suspension, abandonment and reclamation activities are actually to be conducted.

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135 *Supra* note 117.

136 *Informational Letter IL 89-4: Public Involvement in the Development of Energy Resources*; *Informational Letter IL 90-14: Notification to Transport Canada of Drilling Operations Near Aerodromes*; *Interim Directive ID 82-03: Well Licence Applications Early Information for Landowners (Revised)*; *Interim Directive ID 96-02: Facility Application Requirements*; *Interim Directive ID 97-07: Facility Applications — Well Licensing Requirements*; *Guide 17-2: Well-Site Selection and the Surface Owner*; *Guide 17-3: Pipeline and Surface Rights*; and *Guide 62: Responding to Public Concerns About Oil and Gas in Alberta*.

137 (3 November 2003), Directive 001 (AEUB) [*Directive 001*].

Interim Directive ID 2001-08: Revised Licensee Liability Rating (LLR) Program and Energy Development Licence Transfer Requirements[138] established the LLR Program, which is a program to assess the financial viability of a licensee based on the ratio of its deemed assets to its deemed liabilities. The estimated abandonment and reclamation costs used in determining the deemed liabilities in the LLR are average values developed with industry input. Appendix 10 of *ID 2001-08* identifies three situations where a licensee, subject to financial security deposits, may initiate a site-specific liability assessment to permit a more accurate assessment of those deemed liabilities. This voluntary process is available only to a licensee with an LLR less than the deposit threshold currently set at one. To use this provision, a licensee must submit separate liability assessments for each of its facilities or each of its wells to ensure that the review is complete and does not assess just selected low-cost sites.

In certain situations the AEUB may require the licensee to conduct a site-specific assessment using the methodology specified in *Directive 001*. These circumstances are where the AEUB expects a site to have a reclamation cost at least four times greater than the deemed reclamation liability normally calculated for a site of that type in that region of Alberta. Conditions that may result in a site being identified by the AEUB as a potential problem site include:

- insufficient recovery of spilled or released produced fluids or oilfield waste;
- significant off-lease damage to soil, vegetation or a water body;
- evidence or high probability of groundwater contamination; and
- extraordinary surface reclamation issues, such as an extensive cut and fill.

Directive 001 sets out applicable assessment standards and prescribes the methods of estimating suspension, abandonment, remediation and reclamation costs. It further requires that assessors must meet certain qualifications.

Once a site-specific liability assessment is filed with and accepted by the AEUB, then that liability assessment is used to adjust the licensee's deemed liability applied in the LLR calculation.

10. *BULLETIN 2004-02: STREAMLINING EUB DOCUMENTS ON REGULATORY REQUIREMENTS*[139]

In early January 2004 it was announced that the AEUB has begun an initiative to review and streamline AEUB requirements contained in interim directives, informational letters and guides, as well as to update and clarify the requirements. First, the AEUB will issue only "directives," which replace interim directives, informational letters and guides. Directives are documents setting out new or amended AEUB requirements or processes to be implemented and followed by licensees, permittees and other approval holders under the jurisdiction of the AEUB. Existing interim directives, informational letters and guides are to be reviewed and renamed as the initiative progresses.

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138 (4 December 2001), ID 2001-08 (AEUB), rescinded by *Directive 006* (1 June 2004) [*ID 2001-08*].
139 (5 January 2004), Bulletin 2004-02 (AEUB) [*Bulletin 2004-02*].

Second, the AEUB has renamed general bulletins as "bulletins." These contain announcements to inform the energy industry and the public of an AEUB activity, such as a consultation, a new program, electronic submission of data or a new publication. Bulletins do not set out AEUB requirements.

In *Bulletin 2004-02* the AEUB also included a helpful list of all existing bulletins, directives, interim directives, information letters and guides that were in effect as of 1 January 2004.