RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO ENERGY LAWYERS

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The purpose of this article is to highlight and discuss legislative and regulatory developments relevant to energy lawyers, including electricity matters and related jurisprudence, that have arisen during the period between May 2011 and April 2012. This article focuses primarily on decisions before the relevant courts and tribunals in the areas of facilities approvals, Aboriginal consultation, environment, licences, tolls and tariffs, scoping, standing and participant funding, and administrative law. In addition, this article highlights developments in legislation, policy, and guidelines.

Le but de cet article consiste à souligner et discuter les développements législatifs et réglementaires, intéressant les avocats du secteur énergétique, incluant les questions sur l'électricité et la jurisprudence connexe, qui ont surgi entre mai 2011 et avril 2012. Cet article cible essentiellement les décisions attendues des cours et des tribunaux compétents dans le domaine de l'approbation des installations, des consultations des Autochtones, de l'environnement, des permis, des tarifs de droit, du cadrage, du financement permanent et des participants et du droit administratif. En outre, l'article souligne les développements sur le plan législatif, des politiques et des directives.

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I. FACILITIES

A. ALBERTA COURT OF APPEAL

1. *BIG LOOP CATTLE CO. LTD. V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*

The decision in *Big Loop Cattle Co. Ltd. v. Alberta (Energy Resources Conservation Board)*[1] considered whether the Eden Valley Indian Reserve should properly have been characterized as an "urban centre," which would have necessitated a 1.5 km setback from a sour gas pipeline, as opposed to the 320 metre setback approved by the Energy Resources Conservation Board (ERCB) in the underlying decision. This decision is of interest to energy lawyers as it suggests that the ERCB must consider definitions in the *Municipal Government Act*[2] when determining the appropriate setbacks for sour gas pipelines.

a. Application

The applicants appealed the finding of the ERCB that the Eden Valley Indian Reserve did not meet the definition of an urban centre in the ERCB Directive 056[3] in the context of an application to construct and operate a sour gas pipeline.

b. Background

The Eden Valley Indian Reserve had approximately 100 homes and 650 residents at the time of the hearing. Prior to the hearing and in response to a request from the proponent, the ERCB concluded that the Reserve's population density was less than eight dwellings per quarter section and, therefore, the Reserve did not qualify as either an urban centre or an

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1 2012 ABCA 64, 522 AR 325 [*Big Loop Cattle*].
2 RSA 2000, c M-26.
3 *Energy Development Applications and Schedules*, ERCB Directive 056 (26 September 2011) at A-18 [Directive 056].

unrestricted country development, which would have necessitated a 1.5 km setback from the applied for sour gas pipeline, as opposed to the 320 metres setback approved by the ERCB.[4]

c. Key Findings

The Court concluded that the ERCB's decision not to characterize the Reserve as an urban centre fell outside of the range of acceptable and rational outcomes that are defensible in respect of the facts and law.[5] The Court found that Directive 056 required the ERCB, when determining whether a reserve is an urban centre, to consider whether it is a "city, town, village, summer village, or hamlet with not fewer than 50 separate buildings, each of which must be an occupied dwelling, or any similar development."[6] The Court stated that although "city, town, new town, village, summer village, or hamlet" are not defined in Directive 056, they are defined in the *Municipal Government Act*.[7] Finding that the Reserve would have qualified as a hamlet or a village under the *Municipal Government Act*, the Court stated the ERCB should have designated the Reserve as a "similar development."[8]

d. Decision

The appeal was allowed and the matter was remitted back to the ERCB for reconsideration and redetermination in accordance with the Court's findings.

2. *SHAW V. ALBERTA (UTILITIES COMMISSION)*

The decision in *Shaw v. Alberta (Utilities Commission)*[9] marks the first time the Alberta Court of Appeal has been asked to interpret the "critical transmission infrastructure" provisions created by recent amendments to the *Electric Utilities Act*,[10] the *Alberta Utilities Commission Act*,[11] and the *Hydro and Electric Energy Act*[12] (collectively referred to as the Legislation).

a. Application

The applicants were interveners before the Alberta Utilities Commission (AUC) in the Heartland Proceeding,[13] the first hearing before the AUC to consider a project deemed to be critical transmission infrastructure (CTI). In seeking leave to appeal the AUC's decision, the applicants argued that the approval of the line was not in the public interest and that the AUC erred in its interpretation of the amendments to the Legislation designating CTI projects.[14]

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4 *Big Loop Cattle*, *supra* note 1 at para 5.
5 *Ibid* at para 11.
6 Directive 056, *supra* note 3 at A-18. See *Big Loop Cattle*, *ibid* at para 14.
7 *Big Loop Cattle*, *ibid*.
8 *Ibid* at para 17.
9 2012 ABCA 100, [2012] AJ no 289 (QL) [*Shaw*].
10 SA 2003, c E-5.1.
11 SA 2007, c A-37.2.
12 RSA 2000, c H-16.
13 AUC, *AltaLink Management Ltd and EPCOR Distribution & Transmission Inc, Heartland Transmission Project* (1 November 2011), AUC Decision 2011-436 [Heartland Proceeding]. The Heartland Proceeding considered and approved the construction and operation of a major transmission line known as the Heartland Transmission Line and substation.
14 *Shaw*, *supra* note 9 at para 2.

It was also argued that leave ought to be granted because of an apprehension of bias arising from the Minister of Energy's intervention in the decision making process.[15]

b. Background

The Heartland project was the first project to be considered by the AUC under Bill 50,[16] which amended Part 2.1 of the *Electric Utilities Act*, sections 17(1) and (2) of the *Alberta Utilities Commission Act*, and sections 13.1(1) and (2), and 19(1) and (1.1) of the *Hydro and Electric Energy Act* to remove the AUC's authority to consider the "need" for a class of projects created by the legislation and referred to as CTI.

The applicants argued that one of the most important issues in the proceeding was the interpretation of the amended legislation and, in particular, how it shaped the AUC's consideration of CTI projects.[17] In the course of the Heartland Proceeding, the AUC stated that its interpretation of the new legislative framework defined the scope of the AUC's public interest mandate.[18]

The applicants stated that the interpretation arrived at by the AUC, namely, that "Bill 50 restricted the [AUC] from considering whether the social and economic impacts of the construction and operation of the Heartland Transmission Line [was] in the public interest,"[19] was an error of law or jurisdiction that warranted leave being granted by the Court.

In the Heartland Proceeding, the AUC stated that it considered the legislative amendments to mean that the legislature intended to transfer the approval of the need for CTI from the AUC to the legislature, while ensuring that the AUC continued to exercise its public interest mandate over the impacts of specific facilities proposed in the application.[20]

The AUC acknowledged that the applicants' evidence during the proceeding touched upon social and economic implications of approving projects described in the Alberta Electric System Operator's long-term plan, including the Heartland project.[21] Though the AUC considered this evidence, it noted that its mandate related to the proposed alternative configurations of the project and the related social and economic effects, rather than the overall need for the Heartland project.[22]

A second ground of appeal was raised in relation to a perceived bias arising from the intervention by the Minister of Energy, wherein the Minister asked the AUC to suspend its consideration of the project shortly before the anticipated release of the decision.[23] It was

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15 *Ibid* at para 12.
16 *Electric Statutes Amendment Act, 2009*, 2d Sess, 27th Leg, Alberta, 2009 (assented to 26 November 2009), SA 2009, c 44 [Bill 50].
17 *Shaw*, *supra* note 9 at para 3.
18 *Ibid*.
19 *Ibid* at para 4.
20 *Ibid* at para 7.
21 *Ibid* at para 9.
22 *Ibid* at para 10.
23 *Ibid* at para 12.

argued that a request by the government that the AUC suspend its consideration of the project indicated that the government was influencing the AUC's decision.[24]

c. Key Findings

In relation to the first ground, the Court considered it very important that the new legislative framework for CTI be interpreted to provide consistency and certainty to the AUC's mandate.[25] In relation to the second ground, the Court noted that the government was not a party to the proceedings before the AUC. Furthermore, the Minister did not instruct his officials to seek intervener status or to formally provide notice to concerned parties that the government was requesting that the AUC's consideration be suspended.[26] The Court determined that the test for leave to appeal was satisfied in relation to both grounds of appeal.[27]

d. Decision

Leave to appeal was granted on both grounds.

3. *PEMBINA INSTITUTE FOR APPROPRIATE DEVELOPMENT V. ALBERTA (UTILITIES COMMISSION)*

In *Pembina Institute for Appropriate Development v. Alberta (Utilities Commission)*,[28] the Pembina Institute sought leave to appeal an interim decision of the AUC to expedite the hearing process and grant the application of Maxim Power Corp. (Maxim Power) to construct a coal-fired power plant. The interim and final decisions of the AUC in relation to this approval are surveyed later in this article.[29] This decision is noteworthy because the Court determined that an appeal of an interim decision may be rendered moot where a final decision has been subsequently made and the Court confirmed the AUC's discretion to control its own process.[30]

a. Application

The Pembina Institute sought leave to appeal the interim decision of the AUC, which granted approval to Maxim Power to construct and operate a new 500-MW coal power plant. The primary ground of appeal was that the AUC erred in considering its jurisdiction when it made its interim decision granting Maxim Power approval and that it did not provide adequate reasons in its interim decision that the power plant was in the public interest.[31]

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24 *Ibid* at paras 14-17.
25 *Ibid* at para 11.
26 *Ibid* at para 19.
27 *Ibid* at paras 11, 20.
28 2011 ABCA 302, 513 AR 387 [*Pembina*].
29 See AUC, *Maxim Power Corp, HR Milner Power Plant Expansion Interim Decision* (30 June 2011), AUC Decision 2011-290 [*Maxim Power Interim Decision*]; AUC, *Maxim Power Corp, HR Milner Power Plant Expansion* (10 August 2011), AUC Decision 2011-337 [*Maxim Power Final Decision*].
30 *Pembina*, *supra* note 28 at paras 22-24.
31 *Ibid* at para 8.

b. Background

Maxim Power applied for approval to construct the new plant in February of 2009. The AUC made numerous information requests to the applicant throughout 2010 and 2011, which culminated in the AUC deeming the application complete on 4 March 2011. Commensurate with deeming the application complete, the AUC issued a notice stating that the application process would not involve a hearing if there were not parties who could demonstrate they may be directly or adversely affected by the project.[32]

Although the Pembina Institute made submissions seeking standing, the AUC determined that it was not a party that may be directly and adversely affected by the decision and denied the Pembina Institute standing.[33] The Pembina Institute asked the AUC to reconsider this decision, but the AUC only confirmed its original decision.[34] The Pembina Institute did not seek leave to appeal that decision.[35]

Maxim Power received approval of its project in an interim decision dated 30 June 2011.[36] Later, the AUC released a final decision confirming the approval and elaborating on its reasons for determining that the project was in the public interest.[37]

c. Key Findings

The Court determined that the Pembina Institute's argument that the AUC had failed to provide adequate reasons for its finding that the power plant was in the public interest was rendered moot by the subsequent release of the final decision.[38] The Court determined that because the application was deemed complete prior to the release of the interim decision, the AUC had all the necessary evidence required to determine that the project was in the public interest.[39] Although the interim decision provided only a brief explanation of the AUC's decision that the power plant was in the public interest, the final decision of the AUC made it clear that all of the relevant factors were considered.[40]

Although it was alleged that the decision to expedite the application was based on Maxim Power's interest in opening its power plant prior to regulations relating to greenhouse gas emissions becoming effective, the Court determined there was no evidence of this.[41] The Court found the interim decision was not based on any irrelevant considerations and that the final decision addressed all relevant considerations with sufficient reasons.[42]

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32 *Ibid* at para 2.
33 See *Maxim Power Interim Decision*, *supra* note 29.
34 See *Maxim Power Final Decision*, *supra* note 29.
35 *Pembina*, *supra* note 28 at para 3.
36 See *Maxim Power Interim Decision*, *supra* note 29.
37 See *Maxim Power Final Decision*, *supra* note 29.
38 *Pembina*, *supra* note 28 at para 22.
39 *Ibid*.
40 *Ibid*.
41 *Ibid* at para 23.
42 *Ibid*.

d. Decision

Leave to appeal was denied.

B. ALBERTA COURT OF QUEEN'S BENCH

1. *321665 ALBERTA LTD. V. EXXONMOBIL CANADA LTD.*

The decision in *321665 Alberta Ltd. v. ExxonMobil Canada Ltd.*[43] considered whether Husky Oil and ExxonMobil Canada Ltd. (ExxonMobil), as tenants in common operating a series of wells representing a large share of the local market near Rainbow Lake, Alberta, breached section 45 of the *Competition Act*[44] and committed a tort by deciding to utilize a single fuel hauler in their operations. This decision indicates that tenants in common conducting oil and gas operations should be aware of the provisions of the *Competition Act* to ensure that they do not violate these provisions when making decisions about how to conduct their operations.

a. Application

321665 Alberta Ltd. (operating under the tradename Kolt Oilfield) sought damages against Exxonmobil and Husky Oil for intentional interference with economic interests and a breach of section 45 of the *Competition Act* for conspiring to reduce competition in the fuel hauling business near Rainbow Lake, Alberta.

b. Background

Kolt Oilfield was a successful fuel hauler operating in the Rainbow Lake area. The only true competitor in the area was Cardusty Trucking. Kolt Oilfield relied primarily on Husky Oil for business.[45] Most of Husky Oil's business in the area was comprised of wells that were jointly operated with ExxonMobil under the name Mosky.[46]

Both Cardusty Trucking and Kolt Oilfield were advised in 1996 that Mosky was considering using only one fuel hauler for all of its properties. The haulers were each asked to submit financial information for Mosky to consider, although no competitive bid process was engaged. In November 1996, both companies were informed that Cardusty Trucking would be getting all of the new contracts for fuel hauling from Mosky.[47] As a result of this decision, Kolt Oilfield was unable to continue operating its business and was shut down within the year.[48]

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43 2011 ABQB 292, 525 AR 238 [*ExxonMobil*].

44 RSC 1985, c C-34. Section 45(1) provides that "[e]very person commits an offence who, with a competitor of that person with respect to a product, conspires, agrees or arranges (*a*) to fix, maintain, increase or control the price for the supply of the product; (*b*) to allocate sales, territories, consumers or markets for the production or supply of the product; or (*c*) to fix, maintain, control, prevent, lessen or eliminate the production or supply of the product."

45 *ExxonMobil*, *supra* note 43 at paras 9, 12.

46 *Ibid* at para 61.

47 *Ibid* at paras 14-17.

48 *Ibid* at paras 18-21.

c. Key Findings

Because Mosky operated the wells as tenants in common rather than as a joint venture or partnership, the Court found that they were capable of entering into anti-competitive behaviour within the meaning of section 45 of the *Competition Act*.[49]

In considering whether an undue lessening of competition had occurred, the Court viewed the market power of the parties in the area as significant, considering that between them, they owned a significant majority of the local producing wells.[50] Also, the Court determined that Mosky's behaviour restricted Kolt Oilfield's opportunities to compete in the fuel-hauling market near Rainbow Lake.[51]

d. Decision

ExxonMobil and Husky Oil were found liable for the tort of unlawful interference with economic interests and a breach of section 45 of the *Competition Act*. As a result, Kolt Oilfield was awarded $5 million in general damages and $500,000 from each party in punitive damages.[52]

C. ENERGY RESOURCES CONSERVATION BOARD

1. DECISION 2011 ABERCB 033: *BERNUM PETROLEUM LTD., APPLICATION FOR A WELL LICENCE, COCHRANE AREA*

This decision of the ERCB considered the requirement to consider alternatives for the surface location of an oil or gas well.[53] The decision emphasizes the importance of considering and presenting alternative locations to the ERCB when applying for a facility licence.

a. Application

Bernum Petroleum Ltd. (Bernum) made an application to the ERCB to drill a well from a surface location north of Highway 1A outside of Cochrane, Alberta. The terms of Bernum's freehold petroleum and natural gas lease specified that it could not drill a well at any location south of Highway 1A.[54]

b. Background

Bernum acquired a mineral lease from Enar Securities Ltd. (Enar), on the condition that Bernum would only drill its well on lands north of Highway 1A. Enar was unwilling to grant a surface lease on its lands south of the highway because of potential commercial and

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49 *Ibid* at para 109.
50 *Ibid* at paras 139-40, 145.
51 *Ibid* at paras 143-44, 172-74.
52 *Ibid* at paras 283, 288.
53 ERCB, *Bernum Petroleum Ltd, Application for a Well Licence, Cochrane Area* (16 November 2011), 2011 ABERCB 033.
54 *Ibid* at para 15.

residential developments that might be impacted by the presence of a well.[55] Bernum informed the ERCB that, despite this condition, it had already determined a preferred location for drilling on lands north of Highway 1A.[56]

The application was opposed by the Bancroft family, on whose land the well would have been drilled. They argued that the effect of the condition in the lease concerning surface location was that Bernum failed to consider viable locations for the well on land south of Highway 1A.[57]

c. Key Findings

The Bancrofts were successful in persuading the ERCB that there may be viable surface locations south of Highway 1A.[58] The ERCB was not satisfied that Bernum presented sufficient analysis to demonstrate that it had considered viable alternative locations to their preferred surface location.[59]

The ERCB stated that it considers it "very important for … applicant[s] to assess alternative locations and to present analyses of the social, economic, and environmental factors"[60] considered in determining a preferred surface location. It was noted that this is especially important where there are objections to the proposed location.[61]

d. Decision

The ERCB declined to grant the application, however, without prejudice to Bernum's ability to reapply in a future application.

2. DECISION 2011 ABERCB 035: *SUNSHINE OILSANDS LTD., ATHABASCA OIL SANDS CORP., TOTAL E&P CANADA LTD., AND PERPETUAL ENERGY OPERATING CORP.*

This decision of the ERCB considered the risk posed to bitumen deposits by natural gas wells in the Athabasca Oil Sands Area and the corresponding need to shut-in such wells.[62] This decision confirms that where natural gas resources are in communication with bitumen deposits, those wells may be shut-in to facilitate the recovery of such bitumen.

a. Application

Applications were brought by Sunshine Oilsands Ltd., Athabasca Oil Sands Corp., Total E&P Canada Ltd., and Perpetual Energy Operating Corp. for the permanent shut-in of those

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55 *Ibid* at para 13.
56 *Ibid* at para 18.
57 *Ibid* at para 17.
58 *Ibid* at para 69.
59 *Ibid* at para 74.
60 *Ibid*.
61 *Ibid*.
62 ERCB, *Sunshine Oilsands Ltd, Athabasca Oil Sands Corp, Total E&P Canada Ltd, and Perpetual Energy Operating Corp, Applications and a Request for the Shut-in and Production of Gas Liege Field, Athabasca Oil Sands Area* (13 December 2011), 2011 ABERCB 035.

gas wells determined to be in communication with bitumen in the Athabasca Oil Sands Area.[63]

b. Background

A number of natural gas wells located approximately 100 km northwest of Fort McMurray were identified as being in communication with bitumen deposits in the area. It was argued that the continued production of gas from those pools presented an unacceptable risk to bitumen recovery in the area.

c. Key Findings

It was determined that the continued production from the gas wells in communication with the bitumen deposits constituted an unacceptable risk to future in situ bitumen recovery.[64]

d. Decision

The potential threat to bitumen recovery in the Athabasca Oil Sands Area prompted the ERCB to determine that there was sufficient urgency to justify the shut-in of all 691 wells considered to be in communication with bitumen in the area.[65] This decision confirms earlier ERCB decisions that have accorded primacy to bitumen development where it comes into conflict with natural gas development.[66]

3. DECISION 2011 ABERCB 029: *THE CITY OF CALGARY, APPLICATION PURSUANT TO SECTION 33 OF THE* PIPELINE ACT *FOR THE RELOCATION OF A PIPELINE*

This decision of the ERCB considered the ERCB's powers under section 33 of the *Pipeline Act*[67] to order the relocation of a pipeline in the public interest.[68] This decision is noteworthy as it is one of only a handful of reported decisions that have dealt with the ERCB's authority to require the relocation of a pipeline under section 33 of the *Pipeline Act*.

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63 *Ibid* at paras 2-5.

64 *Ibid* at para 16.

65 *Ibid*.

66 See e.g. ERCB, *Sunshine Oilsands Ltd and Total E&P Canada Ltd: Applications for Interim Shut-in of Gas, Liege Field, Athabasca Oil Sands Area* (15 October 2009), ERCB Decision 2009-061; ERCB, *Athabasca Oil Sands Corp: Requests for Interim Shut-in of Gas, Liege Field, Athabasca Oil Sands Area* (10 May 2011), 2011 ABERCB 012.

67 RSA 2000, c P-15. Section 33 states:

> (1) When in its opinion it would be in the public interest to do so, the Board may, on any terms and conditions it considers proper, direct a licensee
> (a) to alter or relocate any part of the licensee's pipeline,
> (b) to install additional or other equipment on the licensee's pipeline, or
> (c) to erect permanent fencing on the right of way or provide any other protective measures within the controlled area that the Board considers necessary.
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> (2) Where the Board directs the alteration or relocation of a pipeline, the installation of additional or other equipment on a pipeline, the erection of fences or the provision of other protective measures within the controlled area, it may order by whom and to whom payment of the cost of the work and material, or either, shall be made.
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> (3) If a dispute arises as to the amount to be paid pursuant to an order under subsection (2), it shall be referred to the Board and the Board's decision is final.

68 ERCB, *The City of Calgary, Application Pursuant to Section 33 of the* Pipeline Act *for the Relocation of a Pipeline* (13 September 2011), 2011 ABERCB 029.

a. Application

The City of Calgary filed an application to the ERCB to have a pipeline relocated to allow for the construction of a municipally sanctioned road widening project. The application also requested that the ERCB determine which party was required to bear the cost of the relocation.

b. Background

The City of Calgary (the City) required the relocation of a pipeline running along 52nd Street S.E. to accommodate the widening of the road from two to six lanes. Following the breakdown of negotiations between the City and Alberta Products Pipeline Ltd. (APPL), the City applied to the ERCB, pursuant to section 33 of the *Pipeline Act*, for an order requiring APPL to relocate the pipeline.[69] The City asked the ERCB to consider its application in two stages. First, it asked the ERCB to determine if the relocation of the pipeline was in the public interest. Second, it asked the ERCB to consider the allocation of costs related to the relocation.[70]

The application was opposed by APPL because the City had developed a modified four lane configuration as an interim measure that did not require relocation of the pipeline (in other words, so as to allow partial road widening to begin immediately). APPL submitted that this raised issues concerning the City's need to widen the street to six lanes.[71]

Both parties expressed concern regarding the continued safe operation of the pipeline under the proposed six lane configuration advanced by the City if the pipeline were to remain in its current location.[72]

An agreement was reached between the City and APPL prior to the oral hearing that provided for the relocation of the pipeline. However, in accordance with the agreement between the parties, the ERCB issued a written decision that set out a number of key findings.[73]

c. Key Findings

As a preliminary matter, the ERCB agreed with the City's request to have the application dealt with in two stages, first determining whether relocation was in the public interest, and subsequently considering the costs of the relocation and the appropriate allocation of costs between the parties.[74] The ERCB considered the relocation of the pipeline to be in the public interest.[75] The City's application to relocate the pipeline was considered to be reasonable on

69 *Ibid* at para 2.
70 *Ibid* at para 3.
71 *Ibid* at para 4.
72 *Ibid* at para 13.
73 *Ibid* at para 11.
74 *Ibid* at para 6.
75 *Ibid* at para 15.

the basis that the City was pursuing "its legislative objective of developing effective transportation systems."[76]

APPL was required to file an application pursuant to Directive 056 to have the pipeline relocated and the agreed upon relocation design was to utilize the City's right of way to minimize the impact of the relocation on adjacent landowners.[77]

d. Decision

The relocation of the pipeline was determined to be necessary for its continued safe operation and was ordered relocated according to the terms of the agreement reached between the parties.

4. 2012 ABERCB 005: *KALLISTO ENERGY CORP., APPLICATION FOR A WELL LICENCE, CROSSFIELD EAST FIELD*

In this decision, the ERCB considered an application to drill a well in the vicinity of the Crossfield gas storage reservoir.[78] This decision is noteworthy because the ERCB considered an alleged conflict between the provincial interest in developing the oil and gas resource and protecting the underground natural gas storage industry.

a. Application

Kallisto Energy Corp. (Kallisto) applied to the ERCB for approval of a licence to drill a vertical well located approximately 2 km from the boundary of the CrossAlta Gas Storage & Services gas storage reservoir.

b. Background

CrossAlta Gas Storage & Services Ltd. (CrossAlta), a joint venture of BP Canada Energy Company and TransCanada Pipelines Ltd, owns and operates a gas storage scheme using the depleted Crossfield East Elkton A and D pools.[79]

During the fracking of a nearby well in 2001, it became clear there was communication between the Basal Quartz "A" pool and CrossAlta's storage reservoir located in the Elkton zone.[80] CrossAlta opposed Kallisto's application on the basis that the fracking of the proposed well in the Basal Quartz would pose a significant risk to the integrity of CrossAlta's gas storage reservoir.[81]

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76 *Ibid* at para 10.
77 *Ibid* at para 16.
78 ERCB, *Kallisto Energy Corp, Application for a Well Licence, Crossfield East Field* (24 February 2012), 2012 ABERCB 005.
79 *Ibid* at para 2.
80 *Ibid* at para 9.
81 *Ibid* at paras 7-10.

CrossAlta argued that the risk of communication between the proposed well and the storage reservoir was significant, and that the right of Kallisto to exploit its mineral rights were outweighed by the public interest in maintaining the integrity of the pool.[82]

c. Key Findings

The ERCB found that the balance of evidence did not support CrossAlta's contention that pressure communication between the Basal Quartz "A" pool and the storage reservoir was caused by fracking operations in the past.[83] Also, the ERCB determined that previous fracking operations had been performed in much closer proximity to the storage reservoir than that proposed in Kallisto's application.[84] As a result, the ERCB did not consider there to be a high risk of communication between the proposed well and the storage reservoir.[85]

The ERCB found that, although gas storage facilities perform a public function, risk to the integrity of the storage reservoir must be balanced against the public interest in exploring and developing nearby hydrocarbon resources. The ERCB stated that where that risk can be appropriately managed, such developments should be permitted.[86]

The ERCB determined that the fracking of the proposed well presented only minimal risk to the integrity of the storage reservoir and that this risk was acceptable.[87]

d. Decision

The ERCB approved Kallisto's application to develop the well.

D. ALBERTA UTILITIES COMMISSION

1. DECISION 2011-329: *NATURENER ENERGY CANADA INC., 162-MW WILD ROSE 2 WIND POWER PLANT AND ASSOCIATED EAGLE BUTTE SUBSTATION*

This decision of the AUC concerned an application to construct and operate a 162-megawatt wind generation project to be known as the Wild Rose 2 Wind Power Plant and the associated Eagle Butte substation (collectively referred to as Wild Rose 2).[88] This decision highlights factors relevant to the AUC's consideration of wind power facilities and is of interest as it marks the first time a hearing has been held by the AUC to consider an objection to a wind facility.

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82 *Ibid* at paras 35, 55.
83 *Ibid* at paras 38-39.
84 *Ibid* at para 40.
85 *Ibid* at paras 49-51.
86 *Ibid* at paras 73-74.
87 *Ibid* at para 82.
88 AUC, *NaturEner Energy Canada Inc, 162-MW Wild Rose 2 Wind Power Plant and Associated Eagle Butte Substation* (2 August 2011), AUC Decision 2011-329 [AUC Decision 2011-329].

a. Application

NaturEner Canada Inc. (NaturEner) filed an application with the AUC pursuant to sections 11, 14, and 15 of the *Hydro and Electric Energy Act*[89] for approval to construct and operate Wild Rose 2.

b. Background

This application involved the construction of 108 wind turbines, as well as a substation to distribute the electricity generated. A number of environmental groups, land owners, and other interested parties participated in the hearing process.[90]

NaturEner submitted that all of the proposed facilities were to be located on privately owned land, and that Cypress County approved bylaw amendments for land use changes required for the project and had designated the area a Wind Energy Facility district.[91] The County did not indicate having any concerns regarding the project. The interveners argued that the development of a wind farm in the area would have negative impacts on the environment and property values and that the noise and visual impact of the wind farm would be detrimental to local landowners.[92]

NaturEner contacted Alberta Culture and Community Spirit and submitted a Historical Resources Overview for clearance approval pursuant to AUC Rule 007.[93] NaturEner also put forward approvals from Transport Canada, a non-objection letter from NAV Canada, and a development permit granted by Cypress County.[94]

c. Key Findings

It was determined that the potential impacts on lands, including impacts to wetlands, animal habitats, rare plants, and native grasslands, by construction and operation of the Wild Rose 2 were acceptable and could be appropriately mitigated. The AUC determined that such mitigation weighed in favour of approving the application.[95]

The AUC did not consider evidence presented by the interveners suggesting that their property values would be negatively affected to be compelling, instead considering the positive social and economic effects arising from the construction and operation of the Wild Rose 2 to outweigh these concerns.[96] Also, the AUC did not consider those arguments related to noise and visual impact to weigh in favour of denying the application.[97]

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89 *Supra* note 12.
90 AUC Decision 2011-329, *supra* note 88 at paras 6, 10.
91 *Ibid* at para 15.
92 *Ibid* at paras 144, 156.
93 *Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations*, AUC Rule 007 (21 April 2009). See AUC Decision 2011-329, *ibid* at para 16.
94 AUC Decision 2011-329, *ibid* at para 17.
95 *Ibid* at paras 57, 98.
96 *Ibid* at para 118.
97 *Ibid* at paras 138, 151.

d. Decision

The AUC approved the application, finding it to be in the public interest. The approval was conditional upon NaturEner entering into an agreement with a conservation agency to develop a 97 hectare off-site native pasture and habitat compensation area. NaturEner was also required to perform post-construction monitoring with respect to wildlife and noise impacts.[98]

2. DECISION 2011-290: *MAXIM POWER CORP., HR MILNER PLANT EXPANSION INTERIM DECISION* AND DECISION 2011-337*: MAXIM POWER CORP., HR MILNER POWER PLANT EXPANSION*

These decisions of the AUC concern the approval to construct and operate a 500-MW coal-fired power plant.[99] These decisions are noteworthy because the AUC approved the application on an expedited basis, in advance of changes to legislation governing coal-fired power plants. As previously indicated, the AUC's decision to expedite the process became the subject of an appeal.[100] The Pembina Institute was ultimately denied leave to appeal the AUC's decision.

a. Application

Maxim Power applied to the AUC in accordance with section 11 of the *Hydro and Electric Energy Act*[101] for approval to construct and operate a new 500-MW coal-fired power generating unit at its existing HR Milner Generating Station.

b. Background

The AUC received correspondence in June 2011 from Maxim Power requesting the expeditious approval of its application without a hearing.[102]

To operate the plant, Maxim Power required approval from Alberta Environment, Alberta Sustainable Resources Development, Transport Canada, NAV Canada, and Alberta Culture and Community Spirit, in addition to the approval of the AUC. It was noted that Maxim Power had engaged many of these governmental departments and agencies prior to submitting the application to the AUC. The environmental impact assessment related to the plant was completed prior to the AUC hearing.[103]

Maxim Power provided satisfactory responses to all information requests from the AUC during the review of the application and addressed all issues within the jurisdiction of the AUC.[104]

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98 *Ibid* at paras 192, 194, 196.
99 See *Maxim Power Interim Decision*, *supra* note 29; *Maxim Power Final Decision*, *supra* note 29.
100 See *Pembina*, *supra* note 28.
101 *Supra* note 12. Section 11 states: "No person shall construct or operate a power plant unless the Commission, by order, has approved the construction and operation of the power plant."
102 *Maxim Power Interim Decision*, *supra* note 29 at para 5.
103 *Maxim Power Final Decision*, *supra* note 29 at paras 7-8, 10.
104 *Ibid* at paras 16-17.

c. Key Findings

It was determined that the proposed plant would pose minimal negative social impacts, while having positive economic impacts, and that the proposed design would minimize negative effects on air quality.[105] It was also noted that the new power plant would be required to comply with the *Specified Gas Emitters Regulation*[106] in relation to greenhouse gas emissions.[107]

Considering the advanced stage of the approval process and the lack of interveners granted standing, the AUC expedited final approval of this project without a public hearing.[108]

d. Decision

Maxim Power's application to construct the plant was approved by the AUC.

3. DECISION 2011-436: *ALTALINK MANAGEMENT LTD. AND EPCOR DISTRIBUTION & TRANSMISSION INC., HEARTLAND TRANSMISSION PROJECT*

This decision of the AUC is notable, as it is the first decision of the AUC to consider an application to construct and operate a CTI project, in this case, a 500-kV transmission line and associated infrastructure from the Edmonton area to a new substation to be located in the Gibbons/Redwater area.[109] In this part, we highlight the routing issues considered by the AUC in ultimately approving the project.

a. Application

AltaLink Management Ltd. (AltaLink) and EPCOR Distribution & Transmission Inc. (EPCOR) filed an application with the AUC for approval to construct and operate the Heartland 12S substation near Gibbons-Redwater, a double-circuit 500-kV transmission line between the existing 500-kV transmission system located on the south side of Edmonton and the Heartland 12S substation, and a double-circuit 240-kV line that would connect the 12S substation to the Alberta interconnected electric system at line 942L.

b. Background

This application was the culmination of considerable planning and preparation by the applicants. It began in 2006 with consultations with various federal, provincial, and municipal government agencies, which resulted in the applicants seeking approval for either the preferred east route or an alternative west route. The east route was proposed to run partly through the existing Edmonton Transportation and Utility Corridor (TUC). The west route

105 *Ibid* at para 70.
106 Alta Reg 139/2007.
107 *Maxim Power Final Decision*, *supra* note 29 at para 70.
108 *Maxim Power Interim Decision*, *supra* note 29 at para 6.
109 Heartland Proceeding, *supra* note 13.

was to be constructed principally on privately owned lands. The AUC hearing compared the environmental, social, and economic effects of the two route alternatives.[110]

Initially, 24,000 stakeholders were consulted in the participant involvement program, but as potential routes were eliminated, the number of stakeholders decreased. An enhanced process was designed by the AUC to maximize the preparation time for parties that may be directly and adversely affected by the AUC's decision on the application. [111]

c. Key Findings

The AUC determined that the preferred east and west routes were the best of four preliminary route options available for the proposed project. Considering the respective social, economic, and environmental impacts of these routes led the AUC to identify the east route as the better option.[112] This option presented fewer impacts, primarily because it would utilize the existing TUC and, thus, avoid impacts related to the development of privately owned land.[113]

Because of site specific concerns raised in regard to the east route, the AUC directed the applicants to make alterations to the plans to minimize and mitigate the effects on area residents. These changes included ensuring that comprehensive sound surveys be performed for the proposed substations within a year of completing the project according to the noise control requirement of AUC Rule 012.[114] Also, the applicants were directed to take electrical and magnetic field readings where the transmission lines passed near schools and to attempt to identify additional options for the routing of transmission lines in the vicinity of Colchester Elementary School.[115]

d. Decision

The AUC determined that the preferred east route, with the changes directed, best met the need for CTI described in government legislation and, as a result, was in the public interest. The AUC recommended approval of the Heartland Project along the preferred east route and ordered conditions that the applicants were to comply with in constructing and operating the line.

4. DECISION 2011-353: *ENMAX BONNYBROOK INC., CONSTRUCT AND OPERATE 165-MW BONNYBROOK ENERGY CENTRE*

In this decision, the AUC considered whether it was within the jurisdiction of the AUC to consider district energy in relation to site selection for a proposed power plant.[116] This decision suggests that district energy issues are not within the jurisdiction of the AUC and

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110 *Ibid* at paras 23-41, 1043.
111 *Ibid* at para 2.
112 *Ibid* at para 1227.
113 *Ibid*.
114 *Noise Control*, AUC Rule 012 (1 April 2012).
115 Heartland Proceeding, *supra* note 13 at paras 1228-29.
116 AUC, *ENMAX Bonnybrook Inc, Construct and Operate 165-MW Bonnybrook Energy Centre* (26 August 2011), AUC Decision 2011-353 [AUC Decision 2011-353].

that this factor will not be considered in relation to site selection issues raised before the AUC.

a. Application

ENMAX Bonnybrook Inc. (EBI) filed an application with the AUC, pursuant to section 11 of the *Hydro and Electric Energy Act*,[117] to construct and operate a 165-megawatt natural gas-fired combined cycle power plant in Bonnybrook, an old industrial neighbourhood in central Calgary.

b. Background

EBI stated that the proximity of the selected site to "existing industry provide[d] an opportunity to develop a more efficient power plant by incorporating district heating and cogeneration capability, allowing for potential environmental advantages."[118] It was noted by EBI that when selecting the site, it considered that the preferred site was in close proximity to customers, which would help build a district energy business.[119]

Bonnybrook Steel Fabricators Ltd. (BSF) opposed the application, arguing that the primary reason for the location of the power plant was its proximity to industrial operations that were potential customers for district energy.[120] BSF argued that in considering EBI's application for the power plant, the AUC should take account of the potential adverse impacts of the construction of the district energy system.[121]

c. Key Findings

The AUC determined that the district energy component of the project was separate and apart from the power plant.[122] As a result, it did not enter into the AUC's determination respecting the proposed site. While the AUC accepted that district energy opportunities influenced EBI's site selection, the AUC did not consider any evidence in relation to the potential impacts of district energy to the Bonnybrook area. The AUC considered such impacts speculative and outside its jurisdiction in making its decision respecting the proposed site.[123]

Finding the issues related to district energy to be outside its jurisdiction, the AUC assessed the application based on its proximity to existing transmission facilities, the availability of water, and the nature of current and projected land use and designation in the area.[124]

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117 *Supra* note 12.
118 AUC Decision 2011-353, *supra* note 116 at para 31.
119 *Ibid* at paras 31, 35.
120 *Ibid* at para 39.
121 *Ibid* at para 40.
122 *Ibid* at para 41.
123 *Ibid*.
124 *Ibid* at para 42.

d. Decision

The AUC determined that the location of the proposed site for the construction and operation of the power plant was suitable. The AUC stated that it was prepared to issue an approval to EBI to construct and operate the power plant, provided it received approval from the Minister of Energy.

5. DECISION 2011-468: *ALBERTA ELECTRIC SYSTEM OPERATOR, NEEDS IDENTIFICATION DOCUMENT, ALTALINK MANAGEMENT LTD., FIDLER 312S SUBSTATION AND 240-KV TRANSMISSION LINE INTERCONNECTION, PINCHER CREEK AREA, DETERMINATION OF PRELIMINARY ISSUES*

This decision involved a preliminary hearing called by the AUC on its own motion to consider whether the need for a transmission line applied for by AltaLink Management Ltd. (AltaLink) had been previously approved by the AUC.[125]

a. Application

AltaLink applied to construct and operate a substation as well as a transmission line. The AUC held a preliminary hearing on its own motion to consider whether the Southern Alberta Transmission Reinforcement Needs Identification Document (SATR NID) — relied on by AltaLink as supporting the need for the transmission line — should be amended by the Alberta Electric System Operator (AESO) and to determine whether AltaLink's application should be combined with a future application for connections commencing from the Fidler substation to a point of interconnection to the 500 kV tie line referred to in the SATR NID as Crowsnest, now identified as Chapel Rock.

b. Background

In Alberta, new transmission projects require NID approval pursuant to section 34 of the *Electric Utilities Act*,[126] as well as facilities approval. AltaLink contended that the need for its proposed transmission line had been previously approved by the AUC when it approved the SATR NID. Local landowners opposed AltaLink's application on the basis that the SATR NID approval was for a different project than what AltaLink was now proposing.[127]

The AUC established this prehearing to determine if the NID from the SATR proceeding had, in fact, approved the need for the transmission line proposed in the current application.[128]

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125 AUC, *Alberta Electric System Operator, Needs Identification Document, AltaLink Management Ltd, Fidler 312S Substation and 240-kV Transmission Line Interconnection, Pincher Creek Area, Determination of Preliminary Issues* (1 December 2011), AUC Decision 2011-468 [AUC Decision 2011-468].

126 *Supra* note 10.

127 AUC Decision 2011-468, *supra* note 125 at paras 46-57.

128 *Ibid* at paras 8-10.

c. Key Findings

The AUC determined that the need for the transmission facilities linking the Fidler substation to the Goose Lake substation had not been approved in the SATR decision.[129] Further, it determined that there were material differences between the facilities proposed in the SATR in terms of geographic location and electrical system configuration and those being proposed by the applicants.[130]

The AUC found that the SATR decision did not provide landowners impacted by the development of the future transmission line in the present application an opportunity to express concerns on the overall project and, as a result, denied those landowners procedural fairness.[131]

d. Decision

The AUC determined that to connect the Fidler substation required either an amendment to the SATR NID or a new NID approval for the interconnecting line as a precondition to continued processing of the Fidler facilities application.

E. FEDERAL/JOINT REVIEW PANELS

1. LOWER CHURCHILL II: JOINT REVIEW PANEL REPORT

A Joint Review Panel (JRP) was appointed by the Newfoundland and Labrador Minster of the Environment and Conservation and the federal Minister of the Environment to assess the environmental effects of construction and operation of hydroelectric facilities on the Lower Churchill River in Labrador.[132]

a. Application

Nalcor Energy proposed to develop two hydroelectric generation facilities on the lower Churchill River in central Labrador, below the existing Churchill Falls hydroelectric development. The project would consist of two dams located at Muskrat Falls and Gull Island, two reservoirs created by the dams, and transmission lines connecting Muskrat Falls, Gull Island, and the existing Churchill Falls facility.

b. Background

The JRP was tasked with performing an environmental assessment of the proposed project. The decision to approve the project in full or in part would be made by the provincial and federal governments.[133]

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129 *Ibid* at para 67.
130 *Ibid* at para 68.
131 *Ibid* at para 76-78.
132 See *Report of the Joint Review Panel: Lower Churchill Hydroelectric Generation Project, Nalcor Energy, Newfoundland and Labrador* (Ottawa: Canadian Environmental Assessment Agency, 2011).
133 *Ibid* at xi.

Nalcor Energy stated that the project was "needed to address the future demand for electricity in Newfoundland and Labrador, develop the province's hydroelectric resources in accordance with the provincial energy policy, secure a renewable future, and generate long-term revenues for the Province."[134] Many participants questioned "why the hydroelectric resources of the Churchill River had to be developed, arguing there were other, more economically and environmentally beneficial ways of meeting domestic energy demand."[135]

c. Key Findings

The JRP concluded that the project would have several significant adverse environmental effects on aquatic and terrestrial environments, culture and heritage, and, potentially, on land and resource uses. On the other hand, the JRP also found that there would be positive economic benefits associated with the project, particularly during construction, and that the Innu Nation would benefit from revenues and business opportunities associated with the project. The JRP concluded that if the entire project were to proceed, the adverse "effects and risks would be outweighed by the potential for large-scale economic benefits."[136]

The JRP determined that the main biophysical benefits associated with the project would be derived from the displacement of greenhouse gases by the generation of renewable power.[137] It was noted there would be a loss of fish, riparian, wetland, and terrestrial habitat and that the project may also pose a risk to the Red Wine Mountain caribou herd. Considering this, the JRP determined that, while the project would not result in net biophysical benefits, these adverse effects could be offset by commitments to permanently protect other land and rivers in Labrador.[138]

The JRP recommended that further financial assessments be carried out by the Province of Newfoundland and Labrador, indicating that if economic and alternative studies showed that there are other ways of meeting electricity demand over the medium term that were economically and socially responsible, the Muskrat Falls portion of the project should not be permitted to proceed.[139] The JRP believed the "Gull Island facility would produce more power at a lower unit cost" and had "greater potential to provide lower cost power to Newfoundland and Labrador and would generate revenues for the Province."[140]

On 15 March 2012, the Government of Canada released its response to the JRP's report.[141] The government concluded that the significant adverse environmental effects identified by

134 *Ibid* at xii.
135 *Ibid*.
136 *Ibid* at 271.
137 *Ibid* at 273.
138 *Ibid* at 274.
139 *Ibid* at 278.
140 *Ibid* at xxxiii.
141 See "Government of Canada Response to the Report of the Joint Federal-Provincial Review Panel for Nalcor's Lower Churchill Generation Project in Newfoundland and Labrador" (15 March 2012), online: Canadian Environmental Assessment Agency <http://www.ceaa-acee.gc.ca/050/documents/54772/54772E.pdf>.

the JRP could be justified in the circumstances, having regard to the expected energy, socio-economic, and environmental benefits of the project.[142]

II. ABORIGINAL CONSULTATION

A. SUPREME COURT OF NEWFOUNDLAND AND LABRADOR

1. *NUNATUKAVUT COMMUNITY COUNCIL V. NEWFOUNDLAND AND LABRADOR HYDRO-ELECTRIC CORP. (NALCOR ENERGY)*

a. Application

In *Nunatukavut Community Council v. Newfoundland and Labrador Hydro-Electric Corp. (Nalcor Energy)*,[143] Nunatukavut Community Council Inc. (Nunatukavut) brought an application against the project proponent, Nalcor Energy, the federal and provincial governments, and several other agencies, alleging that they had failed to adequately consult the Aboriginal group in relation to the development of a hydroelectric dam on the Lower Churchill River. Nunatukavut sought an order from the Court directing that Nalcor Energy and the Government of Newfoundland and Labrador consult with the group and negotiate an impact benefits agreement. This decision deals with Nunatukavut's application for an injunction to stop public hearings in relation to the development until the Court had dealt with the group's claim.

b. Background

Hydroelectric development of the Lower Churchill River was the subject of a JRP process considering the need for and environmental impacts of the development of hydroelectric facilities at Gull Island and Muskrat Falls.[144]

Nalcor Energy was obligated under section 4.8 of the *Environmental Impact Statement Guidelines*[145] to consult with specified Aboriginal groups that may be potentially impacted by the development of the facilities.[146] The federal and provincial governments, as well as Nalcor Energy, held a number of meetings with Nunatukavut between 2007 and 2010 and the group was provided funding to participate in the environmental assessment process.[147]

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142 *Ibid* at 6.
143 2011 NLSCTD 44, 307 Nfld & PEIR 306 [*Nunatukavut*].
144 *Ibid* at para 1.
145 Newfoundland and Labrador Department of Environment and Conservation, *Environmental Impact Statement Guidelines, Lower Churchill Hydroelectric Generation Project, Newfoundland and Labrador Hydro* (July 2008), online: Newfoundland and Labrador Department of Environment and Conservation <http://www.env.gov.nl.ca/env/env_assessment/projects/Y2010/1305/lower_churchill_final_guidelines_en.pdf>. Nalcor Energy was required to demonstrate that it understood the "interests, values, concerns, contemporary and historic activities, Aboriginal traditional knowledge and important issues facing Aboriginal groups, and indicate how these [would] be considered in planning and carrying out the Project."
146 *Nunatukavut*, *supra* note 143 at para 13.
147 *Ibid* at paras 13-18.

The federal government completed the Federal Aboriginal Consultation Framework to be applied in relation to the project, which was provided to Nunatukavut in August 2010.[148] This framework provided for Aboriginal consultation during the initial agreement and consultation on the draft JRP agreement, during the panel process leading up to hearings, during hearings, during consultation on the JRP's Environmental Assessment Report, and during regulatory permitting.[149]

Nunatukavut claimed that despite the frequent contacts it had with both levels of government, it was not meaningfully consulted with or accommodated in relation to the proposed project.[150] The group asserted that it was entitled to a land claims agreement and an impact benefits agreement with the government prior to the approval of the project.[151] Therefore, proceeding with the JRP hearings constituted a breach of the Crown's duty to consult.

c. Key Findings

The Court determined that the allegations in Nunatukavut's claim raised a serious issue deserving consideration.[152] The Court noted that the primary interest of the group was to obtain a land claims agreement and that such agreements are often monetary in nature and designed to compensate Aboriginal groups for the loss of their lands. As such, the Court determined that the potential loss to Nunatukavut was compensable.[153] Alternatively, the Court considered the costs incurred by Nalcor Energy, the province, and the federal government to be substantial should the project be halted and further determined that Nunatukavut could not provide compensation in relief.[154]

In considering whether Nunatukavut would suffer irreparable harm if the project were allowed to proceed, the Court noted that the failure of Nalcor Energy and the federal and provincial governments to consult may constitute irreparable harm.[155] However, the Court noted that Nunatukavut was, in fact, appropriately consulted at all significant milestones of the project and would continue to have opportunities to participate in the assessment process, both during the JRP's hearing and with respect to the JRP's report.[156]

d. Decision

The application for interlocutory injunction was dismissed.

148 *Ibid*.
149 *Ibid* at para 19.
150 *Ibid* at para 21.
151 *Ibid* at para 27.
152 *Ibid*.
153 *Ibid* at para 30.
154 *Ibid* at para 31.
155 *Ibid* at para 36.
156 *Ibid* at paras 38-39.

B. NATIONAL ENERGY BOARD

1. DECISION OH-01-2011: *ENBRIDGE BAKKEN PIPELINE COMPANY INC., ON BEHALF OF EMBRIDGE BAKKEN PIPELINE LIMITED PARTNERSHIP*

This decision of the National Energy Board (NEB)[157] canvassed the factors that the NEB will consider when determining the adequacy of consultation between a proponent and First Nations groups that may be impacted by the construction of new pipeline facilities. The discussion of the decision focuses on the Aboriginal consultation aspects of the NEB's approval.

a. Application

Enbridge Bakken, on behalf of Enbridge Bakken Pipeline Limited Partnership (Enbridge), applied to the NEB for authorization to construct and operate a pipeline transporting "crude oil from the Bakken Formation in North Dakota (ND) and Montana (MT) to refinery markets in North America via a connection with the existing EPI Mainline at its Cromer Terminal near Cromer, Manitoba (MB)."[158] The project involves the construction of a new 123.4 km long crude oil pipeline between Steelman, Saskatchewan and Cromer, Manitoba.

b. Background

Enbridge developed a consultation and engagement program to support the construction of the new pipeline and consulted with potentially affected First Nations groups along the proposed route prior to filing its application.

Eight First Nations groups sought intervener status in the application process.[159] A number of these groups complained that the consultation undertaken by Enbridge was inadequate.[160] The groups claimed that Enbridge's engagement program did not constitute meaningful consultation on potential project impacts on traditional land use activities and Aboriginal rights such as fishing, trapping, plant gathering, and hunting. One group argued that it had intended to purchase three parcels of land within the project right of way for Treaty Land Entitlement (TLE) purposes and suggested that NEB approval of the project may frustrate the group's ability to obtain those lands.[161]

c. Key Findings

The NEB found that Enbridge made sufficient efforts to consult with all potentially impacted groups, and to address concerns that were raised.[162]

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157 NEB, *Reasons for Decision Enbridge Bakken Pipeline Company Inc, on behalf of Enbridge Bakken Pipeline Limited Partnership* (December 2011), NEB Decision OH-01-2011.
158 *Ibid* at 3.
159 See *ibid* at 31-32.
160 *Ibid* at 33-34. For a detailed summary of the consultation activities that Enbridge undertook with potentially affected Aboriginal groups, see *ibid* at 33.
161 *Ibid* at 35-36.
162 *Ibid* at 38.

The NEB determined that 98.5 percent of the Bakken Pipeline would be on privately-held lands and the remaining 1.5 percent would be on occupied Crown land.[163] The NEB determined that no Aboriginal group filed specific evidence indicating that land along the right of way was being used for traditional purposes or that it was likely to be used for such purposes in the foreseeable future.[164]

The NEB was not persuaded by the argument that Board approval may frustrate attempts to make selected TLE land reserve lands. There was no evidence that those lands would be granted as part of a future TLE settlement and the NEB considered the fact that the lands were currently privately occupied to make the interest of the Aboriginal group speculative at best.[165]

Although the NEB found that there was no evidence that traditional rights would be affected within the project right of way, it determined that should there be any impact, it was likely to be minimal since such impacts could be effectively mitigated by the NEB's conditions of approval.[166]

d. Decision

The NEB considered Enbridge's consultation efforts to be sufficient and approved the project as applied for.

C. ONTARIO ENERGY BOARD

1. DECISIONS EB-2011-0040, EB-2011-0041, EB-2011-0042, *APPLICATION BY UNION GAS LIMITED FOR AN ORDER GRANTING LEAVE TO CONSTRUCT A NATURAL GAS PIPELINE AND ANCILLARY FACILITIES*

These decisions[167] concern an application by Union Gas Limited (Union Gas) for an order granting leave to construct a natural gas pipeline and ancillary facilities in the Township of Ear Falls and the Municipality of Red Lake, both in the district of Kenora, Ontario. The decision is of interest on account of the OEB's discussion and analysis of Aboriginal consultation with reference to the Supreme Court of Canada's decision in *Rio Tinto Alcan v. Carrier Sekani Tribal Council*.[168]

This decision of the OEB was appealed to the Ontario Superior Court of Justice (Divisional Court) on 24 August 2011.[169]

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163 *Ibid* at 39.
164 *Ibid*.
165 *Ibid* at 40.
166 *Ibid*.
167 Ontario Energy Board (OEB), *Application by Union Gas Limited for an Order Granting Leave to Construct a Natural Gas Pipeline and Ancillary Facilities, Decision with Respect to Preliminary Questions and Final Decision and Orders* (25 July 2011), OEB Decision EB-2011-0040, EB-2011-0041, EB-2011-0042 [*Union Gas OEB Decision*].
168 2010 SCC 43, [2010] 2 SCR 650.
169 See *Grand Council Treaty #3 v Union Gas Ltd*, Notice of Appeal (filed 24 August 2011), online: OEB <http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_nrelated=uri_292522>.

a. Application

Union Gas filed applications with the OEB on 8 February 2011 relating to proposed natural gas facilities and services in the Red Lake area. These applications requested leave to construct a natural gas pipeline, a Municipal Franchise Agreement for the Municipality of Red Lake, and a Certificate of Public Convenience and Necessity for Red Lake.[170]

b. Background

On 5 May 2011, the OEB received a letter from the Grand Council of Treaty 3 outlining concerns arising from the applications.[171] These concerns related to the adequacy of the Crown's consultation efforts pursuant to the *Constitution Act, 1982*.[172]

c. Key Findings

It was argued by the First Nations groups that the OEB itself was responsible for engaging in consultation with the groups.[173] In considering this argument, it was noted by the OEB that there was nothing in the relevant legislation prohibiting the OEB from directly engaging in consultation.[174] Despite this, the OEB found that it did not have an independent mandate to conduct direct consultation with First Nations. Rather, it found that its mandate was to assess the adequacy of consultation conducted by the Crown.[175]

The OEB noted that the duty to consult can be discharged in a number of ways and did not necessarily require one-on-one consultation between a Crown ministry and a First Nation.[176] The OEB determined that the application process, including an application for environmental review, can serve to ensure that the duty to consult has been properly addressed.

It was submitted by the First Nations groups that the contemplated Crown conduct engaging the duty to consult was the decision of the OEB itself.[177] The OEB rejected this argument, stating that the OEB was not provided explicit authority to engage in consultation itself and that such engagement was contrary to its role as a decision-making authority.[178] The OEB stated the duty was triggered by the activities and approvals required by other Crown actors having some oversight responsibility for the project. As a result, the OEB determined that its role was to satisfy itself that there had been adequate consultation for the project as a whole.[179]

The OEB determined that it was not necessary for a stand alone process of accommodation to occur between the Crown and the First Nations, after which the OEB

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170 *Union Gas OEB Decision*, *supra* note 167 at 2.
171 *Ibid* at 3.
172 Being Schedule B to the *Canada Act 1982* (UK), 1982, c 11.
173 *Union Gas OEB Decision*, *supra* note 167 at 8.
174 *Ibid*.
175 *Ibid* at 12.
176 *Ibid* at 9-10.
177 *Ibid* at 11.
178 *Ibid*.
179 *Ibid* at 11-12.

would evaluate the sufficiency of that process. Instead, the OEB found that the procedural aspects of consultation had been delegated to Union Gas (a private-sector proponent) and that the OEB was in a position to determine whether Union Gas's efforts were sufficient.[180]

In the OEB's view, evaluating consultation efforts through the environmental assessment process before the OEB satisfies the mandate of assessing the adequacy of consultation between the proponent and potentially affected First Nations.[181] Potentially affected Aboriginal groups are provided detailed information about a project, are provided an opportunity to raise concerns, and the proponent is required to address those concerns through mitigation or accommodation. To the extent that a First Nation believes potential impacts on Aboriginal or treaty rights are not appropriately identified or addressed through the environmental assessment process, they are free to respond to the OEB's notice of hearing and address those during the hearing process. Where such concerns are raised, the OEB can address whether consultation efforts related to the project were adequate. Should the OEB determine that consultation or accommodation has not been sufficient, it would have the opportunity to effect changes to the project or dismiss the application.[182]

The OEB considered itself to be better situated to address consultation in relation to the entire project than Crown ministries engaged in smaller aspects of the project. The OEB determined that this accorded with commentary in *Haida Nation v. British Columbia (Minister of Forests)*,[183] suggesting that the duty to consult is best addressed at the strategic planning level, rather than the permitting stage.[184]

d. Decision

The OEB determined that the duty to consult with Aboriginal peoples in relation to the proposed project had been adequately discharged and that the project was in the public interest.

III. ENVIRONMENT

A. ALBERTA ENVIRONMENTAL APPEALS BOARD

1. APPEAL NOS. 10-034, 11-002, 008, AND 023-R: *GAS PLUS INC. AND HANDEL TRANSPORT (NORTHERN) LTD.*

In this decision,[185] the AEAB considered an appeal of an Environmental Protection Order (EPO) issued to Gas Plus Inc. and Handel Transport (Northern) Ltd. (collectively, the Appellants), requiring the remediation of a gas station site and surrounding area in Calgary, Alberta. This decision is noteworthy because the AEAB varied the EPO issued to the

180 *Ibid* at 18-19.
181 *Ibid* at 24.
182 *Ibid* at 24-25.
183 2004 SCC 73, [2004] 3 SCR 511.
184 *Union Gas OEB Decision*, *supra* note 167 at 25.
185 Alberta Environmental Appeals Board (AEAB), *Gas Plus Inc and Handel Transport (Northern) Ltd v Director, Southern Region, Operations Division, Alberta Environment* (29 December 2011), AEAB Appeal Nos 10-034, 11-002, 008, and 023-R.

Appellants to impose stricter conditions relating to remediation of the site. This decision also indicates that the AEAB will not consider private, third party contracts capable of defeating broad public interest aspects of environmental legislation designed to protect the environment, as well as human health and safety.

a. Application

The Appellants brought a Notice of Appeal in relation to the EPO and its amendments, arguing that the remediation techniques and timelines provided in the EPO were inappropriate and that the EPO was "frustrated" as a result of a lease entered into between Gas Plus Inc. (Gas Plus) and its tenant, Bow Liquor Inc. (Bow Liquor).[186]

b. Background

This matter relates to contamination resulting from a release of gasoline at a gas station owned and operated by the Appellants. Some of the contamination migrated into neighbouring residential areas and, as a result, impacted a number of homes.[187] An EPO was issued on 3 December 2010 against the Appellants, requiring them to remediate all the contamination, which was amended on 21 April 2011, 1 June 2011, and again on 13 September 2011.[188] The first and second amendments provided that the contaminated soil from the excavation site be excavated and removed, with work to commence on a specified date. The third amendment permitted the Appellants to "choose whether they would proceed to deal with the contamination on the gas station site by excavating and removing the soil or by building a secant wall (an underground containment wall) around the perimeter of the site."[189]

The Appellants argued that remediation techniques specified in the EPO were inappropriate because the concentration of hydrocarbons found in groundwater were declining and the concentration of hydrocarbons in the soil was small and had reached equilibrium with the groundwater.[190] As a result, the Appellants argued there was no value in removing the soil from site. Additionally, the Appellants argued that construction of a secant wall could cause the plume to move under non-affected areas.[191] Also, it was argued that aggressive intervention may possibly cause the plume to move and that this risk would be mitigated through bioremediation at the site of contamination.[192] The Appellants argued that bioremediation was a more appropriate method of remediating the contamination than removal of the soil and the building of a secant wall.[193]

It was also argued by the Appellants that the EPO was frustrated as a result of an existing lease between Gas Plus and Bow Liquor.[194] This was a novel argument before the AEAB.

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186 *Ibid* at para 3.
187 *Ibid* at para 1.
188 *Ibid* at para 4.
189 *Ibid* at para 2, n 4.
190 *Ibid* at para 12.
191 *Ibid*.
192 *Ibid*.
193 *Ibid*.
194 *Ibid* at para 3.

The Appellants argued that the EPO would require the tenant to vacate the premises so that those premises could be demolished and the soil beneath them remediated. The Appellants argued that there was no force majeure clause or provision in the lease permitting Gas Plus to summarily terminate the lease. The Appellants argued that this prevented them from complying with the EPO.[195]

A number of interveners participated in this hearing, including the City of Calgary, Alberta Health Services, Bow Liquor, and affected local residents.[196]

c. Key Findings

After considering the information and arguments provided by the Appellants and interveners, the AEAB confirmed Alberta Environment's decision to issue the EPO and provided a number of recommendations to vary the order.[197] These additional recommendations primarily provided for specific work to be performed by the Appellants in relation to off-site contamination.[198]

The AEAB noted that while all of the contamination needed to be remediated, the most pressing concerns were the high levels of benzene, toluene, ethylbenzene, and xylene (collectively, BTEX) found both on- and off-site, and the removal of all contaminated materials on-site, as the contamination plume continued to migrate from this location to off-site areas.[199]

The AEAB recommended that the Appellants be directed to confirm the location of all contaminated material on-site and to excavate, remove, and dispose of all such materials, or use other aggressive remediation techniques as approved by the Director of Alberta Environment.[200]

To ensure the proper and expedient remediation of off-site contamination, the AEAB recommended that the Appellants be directed to confirm the location of all contaminated materials off-site and to excavate, remove, and dispose of the entire plume of BTEX material, or use other aggressive remediation techniques approved by the Director of Alberta Environment to address this contamination. For all other off-site contamination, it was recommended the Appellants use in situ bioremediation technology or other remediation techniques approved by the Director.[201]

The AEAB also recommended that the Appellants be directed to perform a number of activities that were not included in the original EPO in relation to off-site contamination. It was suggested the Appellants be directed to take air quality samples from all homes and businesses potentially affected by the contamination within a month of a ministerial order being issued. Where the sample indicates that vapours are entering a home or business, the

195 *Ibid* at para 88.
196 *Ibid* at para 6.
197 *Ibid* at para 83
198 *Ibid* at para 84.
199 *Ibid* at paras 80-83.
200 *Ibid* at para 83.
201 *Ibid* at para 84.

AEAB recommended that the Appellants be directed to install a vapour extraction system or another method of protecting human health.[202] Also, if groundwater monitoring demonstrated that contamination was moving towards the northeast direction, the AEAB recommended the Appellants be directed to construct an interceptor channel to prevent the contamination from moving towards the Bow River.[203] The AEAB recommended that the Appellants be required to comply with these directions within two months of the issuance of a ministerial order.[204]

The AEAB rejected the Appellants' argument that the lease between Gas Plus and Bow Liquor frustrated the Appellants' ability to carry out the work specified in the EPO.[205] The AEAB doubted that the contractual principle of frustration applied to the law of regulatory decision-making. The AEAB determined that such an interpretation would effectively defeat the broad public interest aspects of environmental legislation.[206] The AEAB noted that it did not have the jurisdiction to order Bow Liquor to vacate its property, but considered such issues irrelevant to the AEAB in making recommendations regarding the EPO.[207]

The Appellants sought reconsideration of the AEAB's findings in this decision, but this motion was denied.[208]

d. Decision

The AEAB confirmed Alberta Environment's decision to issue the EPO and provided additional recommendations to be included in a further ministerial order to the Appellants directing them to remediate the contamination.

IV. LICENCES

A. NATIONAL ENERGY BOARD

1. GH-1-2011: *KM LNG OPERATING GENERAL PARTNERSHIP* AND GH-003-2011: *BC LNG EXPORT CO-OPERATIVE LLC*

In these decisions,[209] the NEB considered whether or not the traditional requirements for export licences that required the filing of long-term export purchase and sale contracts were appropriate where liquid natural gas (LNG) was to be exported to Asian markets. These decisions demonstrate that the traditional requirements may be relaxed in relation to the development of new markets and are of interest as they are the first long-term export licences

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202 *Ibid*.
203 *Ibid*.
204 *Ibid* at para 85.
205 *Ibid* at para 104.
206 *Ibid* at para 105.
207 *Ibid* at para 106.
208 See AEAB, *Gas Plus Inc and Handel Transport (Northern) Ltd v Director, Southern Region, Operations Division, Alberta Environment and Water* (8 May 2012), AEAB Appeal Nos 10-034, 11-002, 008 & 023-RD.
209 NEB, *Reasons for Decision KM LNG Operating General Partnership* (October 2011), NEB Decision GH-1-2011 [*KM LNG NEB Decision*]; NEB, *Reasons for Decision BC LNG Export Co-operative LLC*, (February 2012), NEB Decision GH-003-2011 [*BC LNG NEB Decision*].

to be issued since the early 1990s, demonstrating the evolving nature of the Canadian natural gas market.

a. Application

KM LNG and BC LNG both applied for licences with terms of 20 years to export LNG to Asian markets from Bish Cove, near the port of Kitimat, British Columbia, pursuant to section 117 of the *National Energy Board Act.*[210]

b. Background

Export licences are required from the NEB whenever oil or natural gas is to be exported for a term of more than two years if volumes exceed 30,000 m^3 per day.[211] These licences have typically been associated with the export of natural gas to the United States under long-term purchase and sale contracts. KM LNG's application for an export licence was the first time that the NEB had considered an export to Asia in the form of LNG.[212]

At its hearing, KM LNG presented evidence that prospective Asian buyers were not comfortable entering into long-term LNG purchase and sale contracts if there was a risk that those contracts would be made available to the public.[213] KM LNG took the position that the traditional requirement to file copies of export sales contracts with the NEB would prevent KM LNG from exporting LNG to Asian markets.[214] KM LNG argued that there was sufficient evidence demonstrating that typical Asian LNG prices were less favourable to Canadian consumers than domestic prices and that, as a result, there was little risk to those Canadian markets should the NEB grant the licence without strict compliance to traditional requirements designed to protect the Canadian marketplace.[215]

BC LNG applied for the same relief from the traditional requirements for the purchase and sale agreements related to the export of LNG.[216]

c. Key Findings

The NEB accepted KM LNG's arguments that strict compliance with the traditional requirements of purchase and sale agreements, including the requirement to file copies of export sales contracts, was not appropriate for KM LNG's application and that KM LNG should therefore, be exempt from these requirements.[217] BC LNG was also granted similar exemption from these traditional requirements.[218]

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210 See *KM LNG NEB Decision*, *ibid* at 1; *BC LNG NEB Decision*, *ibid* at 1. Section 117(1) of the *National Energy Board Act*, RSC 1985, c N-7 [*NEB Act*] deals with the issuance of licences and provides that "the Board may, on such terms and conditions as it may impose, issue licences for the exportation or importation of oil or gas."

211 *NEB Act*, *ibid*, ss 116-17; *National Energy Board Act Part VI (Oil and Gas) Regulations*, SOR/96-244, ss 14-16.

212 *KM LNG NEB Decision*, *supra* note 209 at 1.

213 *Ibid* at 9.

214 *Ibid*.

215 *Ibid* at 17-19.

216 See *BC LNG NEB Decision*, *supra* note 209.

217 *KM LNG NEB Decision supra* note 209 at 10.

218 *BC LNG NEB Decision*, *supra* note 209 at 17.

The NEB was satisfied that KM LNG's proposed exports would not occur on terms and conditions more favourable to the export market than to the Canadian market, and that the export would not cause Canadians any difficulty in meeting their future energy requirements at fair market prices.[219] The NEB reaffirmed these findings in relation to the application submitted by BC LNG.[220]

d. Decision

The export licences were granted on the terms and conditions sought by KM LNG and BC LNG.

V. SCOPING

A. NATIONAL ENERGY BOARD

1. FILE OF-FAC-OIL-N304-2010-01: *ENBRIDGE NORTHERN GATEWAY (NORTHERN GATEWAY) PROJECT NOTICE OF MOTION FILED 13 OCTOBER 2011 BY LIVING OCEANS SOCIETY, RAINCOAST CONSERVATION FOUNDATION AND FOREST ETHICS*

In this decision,[221] the JRP for the Enbridge Northern Gateway Project was asked to consider the environmental effects of oil sands development in relation to the project. This decision is noteworthy because the JRP confirmed that it would not consider upstream effects in relation to the proposed project. This is consistent with the JRP's practice of limiting issues to those immediately relevant to the project under review.

a. Application

The Living Oceans Society, Raincoast Conservation Foundation, and Forest Ethics (the Coalition) brought a motion requesting that the JRP consider the upstream effects of the Enbridge Northern Gateway Project, including increased development of oil sands.

b. Background

The JRP considered the substance of this motion to be have previously been brought forward "by the Coalition and others through a Panel Session process held between July and September 2010."[222] At that time, the JRP canvassed the public and Aboriginal groups for

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219 *KM LNG NEB Decision*, *supra* note 209 at 18-19.

220 *BC LNG NEB Decision*, *supra* note 209 at 14.

221 Enbridge Northern Gateway Project JRP, *Enbridge Northern Gateway (Northern Gateway) Project Notice of Motion filed 13 October 2011 by Living Oceans Society, Raincoast Conservation Foundation and Forest Ethics* (6 December 2011), File OF-FAC-Oil-N304-2010-01, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/384192/620327/624909/770171/A69-1_-_Panel-Commission_-_Ruling_no._4_-_D%E9cision_no._4_--_Notice_of_Motion_from__Living_Oceans_Society,_Raincoast_Conservation_Foundation_and_Forest_Ethics__-_A2J4Z7?nodeid=770053&vernum=0>.

222 *Ibid* at 1.

submissions in relation to the issues. The JRP reiterated its findings arising from that information session in response to the motion by the Coalition.[223]

c. Key Findings

The JRP noted that oil sands projects are subject to provincial regulation and many undergo environmental assessments and that assessing oil sands development as part of their review may duplicate this environmental assessment process.[224] The proposed project was for transportation only and Northern Gateway did not indicate any intention to develop oil sands projects. Also, the proposed project was not located near any existing or proposed oil sands developments.[225]

The JRP found that there was no direct connection between the proposed project and oil sands development.[226] The JRP determined that the motion brought by the Coalition did not raise any issues that were not previously addressed in the information session, and as a result did not consider it necessary to review, vary, or rescind their previous decision to exclude upstream oil sands development in their review of the Northern Gateway Project.[227]

d. Decision

The motion was denied.

VI. TOLLS AND TARIFFS

A. NATIONAL ENERGY BOARD

1. *ENBRIDGE PIPELINES INC., COMPETITIVE TOLL SETTLEMENT APPLICATION*

The NEB approved the Competitive Toll Settlement agreement submitted by Enbridge Pipelines Inc. (Enbridge Pipelines) in relation to the operation of the Canadian Mainline.[228] This settlement is noteworthy because it provides for the certainty and stability of tolls charged in relation to the pipeline for a ten-year period.

a. Application

Enbridge Pipelines applied to the NEB for approval of the 2011 Competitive Toll Settlement (CTS) in respect of tolls on the Canadian Mainline from 1 July 2011 through 30 June 2021; final tolls on the Canadian Mainline for both 2010 and 2011; and 2011 Canadian

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223 *Ibid* at 2.
224 *Ibid*.
225 *Ibid*.
226 *Ibid*.
227 *Ibid* at 3.
228 NEB, *Enbridge Pipeline Inc (Enbridge) 2011 Competitive Toll Settlement (2011 CTS or CTS) and Final Toll Application* (24 June 2011), File OF-Tolls-Group1-E101-2011-03, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92835/155829/673846/685797/698162/A1Z9W5_-_Letter_and_Order_TO-03-2011_-_Enbridge_2011_Competitive_Toll_Settlement_and_Final_Toll_Application.pdf?nodeid=698163&vernum=0>.

Local Tolls (CLT), associated surcharges, and receipt and delivery tankage tolls, under the CTS, as final tolls on the Canadian Mainline for the period of 1 July 2011 to 30 June 2012.

b. Background

The CTS was developed through negotiation between Enbridge Pipelines and the Canadian Association of Petroleum Producers and established the CLT for all volumes shipped on the Canadian Mainline, as well as International Joint Tariff for all volumes shipped from Western Canada to delivery points on the Lakehead Pipeline System and points downstream of this system.[229]

Previously, the Canadian Mainline was the subject of numerous and varied toll agreements. Many of these tolls were related to specific expansion facilities incorporated into the Canadian Mainline, which required Enbridge Pipelines to calculate tolls according to numerous processes set out in a variety of agreements relating to expansion facilities.[230]

c. Key Findings

The CTS provides a simplified toll structure by establishing a single toll for transportation, receipt, and delivery on the Canadian Mainline.[231] It was also noted that the CTS provides benefits to shippers by providing toll certainty and stability for a ten-year period, as well as by establishing competitive long-term tolls on the Canadian Mainline.[232]

The NEB considered the CTS to be in the public interest because it was an arm's length settlement concluded between interested parties after extensive negotiation.[233] Also, it was consistent with the NEB's efforts to streamline the regulatory process and minimize the degree of oversight associated with the regulation of companies under the NEB's jurisdiction.[234]

d. Decision

The NEB approved this application.

2. DECISION RH-2-2011: *TRANS MOUNTAIN PIPELINE ULC ON BEHALF OF TRANS MOUNTAIN PIPELINE, LP*

This decision of the NEB[235] considered an application by Trans Mountain Pipeline for Firm Service to the Westridge dock to support the development of off-shore markets for Canadian crude oil. This decision is important because the NEB determined that Firm

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229 Enbridge Piplines, *Competitive Toll Settlement Application* (2 May 2011) at paras 3-4, online: Enbridge <http://www.enbridge.com/DeliveringEnergy/Shippers/~/media/www/Site%20Documents/Delivering%20Energy/Shippers/Competitive%20Toll%20Settlement%20Application.ashx>.

230 *Ibid* at paras 13-23.

231 *Ibid* at para 23.

232 *Ibid* at para 28.

233 *Ibid* at para 72.

234 *Ibid*.

235 NEB, *Reasons for Decision Trans Mountain Pipeline ULC on behalf of Trans Mountain Pipeline, LP* (December 2011), NEB Decision RH-2-2011.

Service and related fees provided a reasonable and innovative solution to help develop off-shore markets.

a. Application

Trans Mountain Pipeline made an application to the NEB for Firm Service on the Trans Mountain Pipeline System, as well as approval of tariff amendments to implement the Firm Service and approval to use the Firm Service Fee as a customer contribution.

b. Background

The Trans Mountain Pipeline is currently the only crude and refined petroleum products pipeline providing transportation to the west coast of Canada. Delivery locations include the Westridge dock, used for offshore exports. Due to the unique characteristics of marine deliveries, fuel-supply to the Westridge dock cannot be apportioned in the same manner as supply to land destinations.[236]

Trans Mountain Pipeline identified continued offshore market development as a significant benefit of Firm Service to the Canadian oil industry.[237] Trans Mountain Pipeline submitted that discounts were currently applied to Canadian crude products in off-shore markets because of uncertainty of supply, administrative costs related to acquiring new crude, and the increased cost in processing and testing new crude.[238] Trans Mountain Pipeline argued that Firm Service to the Westridge marine port would provide higher prices for Canadian crude in off-shore markets.[239]

Under the Firm Service program, Firm Service Shippers would be required to pay a Firm Service Toll for their contract for supply over a ten-year period. An element of the toll would be a Firm Service Fee charged by Trans Mountain Pipeline. This fee would be used for the "advancement of capital projects and preliminary activities in support of expansion of the Pipeline."[240]

c. Key Findings

The NEB recognized that "there [were] clear signals of demand for Westridge dock capacity."[241] Despite this, the NEB was not convinced that there would be material benefits for all Canadian producers.[242]

The NEB found that the "certainty of space and cost to the Westridge dock [would] likely enhance the ability of Canadian producers to develop long-term relationships with buyers in new markets and lead to increased acceptance and utilization of Canadian crude oil in non-

236 *Ibid* at 1.
237 *Ibid* at 13.
238 *Ibid*.
239 *Ibid*.
240 *Ibid* at 29.
241 *Ibid* at 14.
242 *Ibid*.

traditional markets."[243] The NEB determined that Firm Service was a reasonable method of balancing the interests of all interested parties and, therefore, approved Firm Service subject to conditions imposed by the NEB.[244]

The NEB noted that Firm Service Fees were established through a competitive bidding process and reflected the value that each bidder placed on the Firm Service to the Westridge docks. It found that this process did not result in unjust discrimination arising in relation to these tolls.[245] In the NEB's opinion, shippers' concerns about the need to reduce uncertainty related to accessing product from the Westridge dock justified a unique solution and the NEB considered Firm Service fees an appropriate response.[246] Further, the NEB considered it likely that the Firm Service Fees charged by Trans Mountain Pipeline would provide overall benefits to all shippers, since the money would be reinvested in capital developments facilitating the supply of Canadian crude to off-shore markets.[247]

d. Decision

The NEB required Trans Mountain Pipeline to file for approval an updated tariff, but generally approved the application for Firm Service to the Westridge docks. It should be noted that this decision is currently subject to a review and variance application brought by Chevron, which alleges that the NEB took into consideration irrelevant considerations by considering market development for Canadian crude producers and the impact of tolls on netbacks and prices to producers.[248]

3. DECISION RH-1-2011: *ENBRIDGE SOUTHERN LIGHTS GP INC.*

This decision of the NEB[249] considered a complaint made by Imperial Oil in relation to tolls charged on the Enbridge Southern Lights Pipeline.

a. Application

Imperial Oil complained to the NEB regarding the 2010 toll filing from Enbridge's Southern Lights Pipeline, claiming that it did not provide sufficient information to permit interested shippers to assess the Southern Lights Toll or demonstrate that the Uncommitted Toll is just and reasonable.

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243 *Ibid* at 28.
244 *Ibid*.
245 *Ibid* at 37.
246 *Ibid*.
247 *Ibid* at 38.
248 NEB, *Chevron Canada Limited (Chevron) — Review and Variance Application Pursuant to Section 21(1) of the* National Energy Board Act *Concerning RH-2-2011 and the Board's 13 January 2012 Letter Decision* (24 May 2012), File OF-Tolls-Group1-T260-2012-0402, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92835/552980/655087/787084/819192/A2T5I1_-_Letter_to_Chevron_Chevron_Canada_Limited_%96_Review_and_Variance_Application_pursuant_to_Section_21(1)_of_the_National_Energy_Board_Act_concerning_RH-2-2011.pdf?nodeid=819018&vernum=0>.
249 NEB, *Reasons for Decision Enbridge Southern Lights GP Inc* (February 2012), NEB Decision RH-1-2011.

b. Background

A Committed Toll was approved by the NEB for the cost of service on the Southern Lights Pipeline that required each committed shipper to pay the toll for its committed volume on a monthly basis over a 15 year term.[250] An Uncommitted Toll was also established, charging twice the value of the Committed Toll for uncommitted volumes entering the pipeline.[251]

Imperial Oil argued that the data required to determine the reasonableness of the Committed Toll was not provided by Enbridge when it filed Tariffs 1 and 2, and that as a result, the toll was unjust and unreasonable.[252] Imperial Oil suggested that the stated elements of the cost of service significantly overstated the actual costs of service.[253] Also, Imperial Oil argued that the Uncommitted Toll was not cost-based and, as a result, was not just and reasonable.[254]

Enbridge stated that the tolls charged were just and reasonable and that sufficient information was provided to justify the tolls.[255] Enbridge argued that the price of the Uncommitted Toll is based on approved toll principles and as a result is just and reasonable.[256]

c. Key Findings

The NEB determined that Enbridge had provided sufficient evidence demonstrating that the Committed Toll was cost-based and had been calculated in a reasonable manner. The NEB also found that the Uncommitted Toll charged was reasonable, considering that the pipeline was underutilized, that all parties had an opportunity to participate in the bidding processes, and that the same rate was charged for all uncommitted volumes.[257] Based on these considerations, the NEB determined that the tolls charged were just and reasonable.[258]

d. Decision

Imperial Oil's complaint was dismissed.

250 *Ibid* at 11.
251 *Ibid*.
252 *Ibid* at 10-11.
253 *Ibid* at 14.
254 *Ibid* at 16.
255 *Ibid* at 15.
256 *Ibid* at 18.
257 *Ibid* at 23-24.
258 *Ibid* at 24-25.

B. ALBERTA UTILITIES COMMISSION

1. DECISION 2011-450: *ATCO GAS GENERAL RATE APPLICATION PHASE 1*

This decision of the AUC[259] involved a review of ATCO Gas' (ATCO) general rate application for the years 2011 and 2012, and is of note because it is the first general rate application brought by ATCO since 2008 and 2009.

ATCO had applied for a review and variance of this decision on the basis that the AUC committed errors of fact, law, or jurisdiction in relation to the various issues addressed in this decision, including that the AUC failed to provide reasonable notice to reduce costs for previously approved service and service levels, denied costs previously approved in closely related costs decisions, as well as issues related to the integration of Nova Gas Transmission Ltd. (NGTL) and ATCO Pipelines Ltd.[260]

a. Application

ATCO filed a 2011-2012 General Rate Application Phase 1 with the AUC on 3 December 2010. ATCO requested approval of its forecasted revenue requirements for the 2011 and 2012 test years that would form the basis for rates to be paid by customers receiving gas distribution services.

b. Background

Prior to this application, ATCO's most recent General Rate Application was for the 2008 and 2009 test years.[261] A General Rate Application was not heard for 2010.

Interveners participating in this application included the City of Calgary and the Office of the Utilities Consumer Advocate.[262]

c. Key Findings

The AUC directed that ATCO provide a compliance filing to update its 2011 opening rate base forecast to address the AUC's findings that insufficient information for certain forecasted expenditures was provided or the expenditures were unwarranted.[263] The AUC rejected forecasted costs relating to support services and internal work-enhancement programs.[264]

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259 AUC, *ATCO Gas (A Division of ATCO Gas and Pipelines Ltd) 2011-2012 General Rate Application Phase 1* (5 December 2011), AUC Decision 2011-450 [AUC Decision 2011-450].

260 AUC, *Application by ATCO Gas for Review and Variance of Decision 2011-450 — Determination of Preliminary Question* (3 February 2012) [*Review and Variance*].

261 See AUC, *ATCO Gas 2008-2009 General Rate Application Phase 1* (13 November 2008), AUC Decision 2008-113.

262 AUC Decision 2011-450, *supra* note 259 at paras 24, 33, 41.

263 *Ibid* at para 83.

264 *Ibid* at paras 438, 441, 443, 450.

The AUC held that the costs of demand side management programs and educational and safety services provided by ATCO via its Edmonton Blue Flame Kitchen office were not properly included in the rate base and revenue requirement for the test years.[265]

Also, the AUC held that ATCO was not entitled to recover costs incurred through participation in NEB hearings related to NGTL and that cost recovery relating to the integration of ATCO Pipelines Ltd. and NGTL was restricted to partial costs arising prior to the General Rate Application hearing.[266]

The application for review and variance subsequently brought by ATCO states that forecasted costs relating to support services and internal work enhancement programs are costs that have been approved by the AUC in previous related decisions and that the failure of the AUC to permit these costs is an error of fact, law, or jurisdiction that prejudices ATCO.[267]

Similarly, the application for review and variance states that costs associated with the Edmonton Blue Flame Kitchen and demand side management are costs that have consistently been approved for inclusion in ATCO's rates prior to Decision 2011-450.[268] ATCO claims that the failure to approve these costs for inclusion represents a retroactive reversing of the AUC's position and that ATCO was not provided a reasonable opportunity to adjust and respond to this change.[269]

Also, ATCO argues that the AUC's finding that ATCO is not entitled to recover costs for participation in NEB hearings relating to NGTL on the basis that ATCO provided "no supporting rationale" is an error of fact.[270] ATCO states that it provided detailed information regarding the complexities of NGTL rate design that justified its participation in NGTL proceedings occurring after integration.[271] Noting that none of the interveners indicated that the rationale provided was not satisfactory, ATCO argues that the AUC provided no advance notice of any of its concerns and, as a result, acted contrary to rules of procedural fairness and natural justice.[272] As a result, ATCO argues that a review of this part of the decision is justified.[273]

ATCO also argues that the AUC's decision to restrict ATCO to recovering costs related to integration with NGTL to those costs incurred prior to the General Rate Application hearing was prejudicial to ATCO, since ATCO was not provided with the AUC's rationale for restricting these costs prior to the hearing and, as a result, was not in a position to respond prior to the AUC making its final decision on this issue.[274]

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265 *Ibid* at para 686.
266 *Ibid* at para 1021.
267 *Review and Variance*, *supra* note 260 at paras 8-11.
268 *Ibid* at para 4.
269 *Ibid* at paras 4-7.
270 *Ibid* at para 13.
271 *Ibid.*
272 *Ibid* at para 14.
273 *Ibid* at para 15.
274 *Ibid* at paras 16-19.

d. Decision

ATCO was required to provide a compliance filing in relation to Decision 2011-450 addressing the directions of the AUC indentified above. ATCO's application for review and variance of Decision 2011-450 has not yet been the subject of a decision by the AUC on the preliminary question of whether ATCO has raised a substantial doubt as to the correctness of the decision.

2. DECISION 2011-474: *2011 GENERIC COST OF CAPITAL*

This decision of the AUC[275] is important because it sets out the approved generic return on equity for all affected utilities for 2011. It also sets out the AUC's findings with respect to the proposal to reintroduce a formula by which the generic return on equity would be adjusted on an annual basis beyond 2011.

a. Application

Decision 2011-474 was a proceeding initiated by the AUC and sets out the approved generic return on equity for all affected utilities for 2011, makes findings with respect to the proposal to reintroduce a formula by which the generic return on equity will be adjusted on an annual basis beyond 2011, and considers the capital market structures of individual utilities.

b. Background

The approved generic return on equity contained in Decision 2011-474 applies to numerous utility companies operating in Alberta including AltaGas Utilities Inc. (AltaGas), AltaLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., and FortisAlberta Inc. (collectively referred to as the Utilities). The Utilities filed a joint submission and sponsored experts to provide evidence.[276]

Interveners participating in the proceeding included the Industrial Power Consumers Association of Alberta, the Alberta Electric System Operator (which registered as the Independent System Operator), the Consumers' Coalition of Alberta, the Office of The Utilities Consumer Advocate, and the Canadian Association of Petroleum Producers. These parties also sponsored experts to provide evidence.[277]

The AUC heard evidence regarding the tests to be considered when determining a fair return on equity, a number of opinions on the proper methodology to be employed for many of the tests, and a wide range of proposed returns on equity.[278]

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275 AUC, *2011 Generic Cost of Capital* (8 December 2011), AUC Decision 2011-474 [Decision 2011-474].
276 *Ibid* at paras 1, 3.
277 *Ibid* at paras 11-12.
278 *Ibid* at para 18.

To satisfy the fair return standard, the AUC considered a capital structure for each utility subject to this proceeding. The AUC accounted for differences in risk among the individual utilities by adjusting their capital structures. This included a review of what expenses are properly contained in an individual utility's rate base, including expenses related to stranded assets.[279]

c. Key Findings

The AUC found that evidence supporting return on equities estimates included:

- changes in the financial environment since the 2009 proceeding [on the generic costs of capital]
- the capital asset pricing model (CAPM)
- the discontinued cash flow model (DCF) which was applied to proxy utilities as well as to the equity market overall
- other evidence on comparable investments
- [return on equity] awards by other Canadian regulators
- market price-to-book values
- returns on high grade bonds
- the return expectations from pension and investment managers
- the impact of growth on the required [return on equity].[280]

On the basis of this evidence, the AUC was presented with a number of recommended values for the return on equity for 2011 and for 2012. The Utilities requested a return on equity of 10.375 percent for 2011. The interveners suggested a return on equity of 8.3 percent for 2011, increased to 8.4 percent for 2012.[281]

The AUC determined that the return on equity "must be based on an estimate of the risk-adjusted opportunity cost of equity capital."[282] The AUC is required to "estimate the return on equity that utility investors are foregoing by having their equity invested in these utilities rather than other investments of similar risk that are available in the market."[283] After reviewing the models and approaches proposed by the Utilities and the interveners, the AUC found that its determination on the appropriate return on equity would be based primarily on

279 *Ibid* at para 169.
280 *Ibid* at para 17.
281 *Ibid* at paras 18-19.
282 *Ibid* at para 143.
283 *Ibid*.

capital asset price modeling and discontinued cash flow modeling.[284] The AUC held that the appropriate rate of equity for 2011 will be 8.75 percent.[285]

The AUC also considered using a formula to calculate the appropriate return on equity for future years. This process had been used by the AUC in the past, but was discontinued as a result of the 2009 credit crisis and the instability of market indicators utilized in the formula. The AUC determined the evidence provided on this issue indicated that, "although there [had] been some improvement in the financial environment, credit markets remain[ed] volatile."[286]

As a result, the AUC found that the use of a formula to determine the generic rate of equity for future years was inappropriate and declined to utilize such a formula, determining that the rate of equity for 2012 will also be 8.75 percent.[287] In considering the capital structure of individual utilities, the AUC found that any stranded assets should not remain in a utility's rate base. The AUC noted that this finding may have certain implications for the quantum of business risks of the transmission utilities, but determined that any adjustments to capital structure would best be dealt with on a case-specific determination where such a situation arose.[288]

AltaGas has made an application for review and variance based on the AUC's findings that stranded assets should not be included in a utility's rate base.[289] The application argues that this finding is prejudicial to utilities because:

- Stranded assets may be retired in the ordinary course of business and utilities should be permitted to recover costs associated with remediation and reclamation of sites where the asset is no longer required;[290]

- This decision is contrary to established regulatory practices and legislated requirements for accounting treatment of depreciable assets provided in the *Uniform System of Accounting for Natural Gas Utilities*;[291] and

- Undepreciated capital costs of any asset retired before the end of its expected life would be removed from the rate base before those costs were recovered.[292]

As a result, AltaGas argued that it was denied a reasonable opportunity to earn a return on and of its capital investment required to meet the obligations and responsibilities prescribed by legislation as a default gas supplier.[293]

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284 *Ibid* at paras 143-44.
285 *Ibid* at para 149.
286 *Ibid* at para 162.
287 *Ibid* at para 167.
288 *Ibid* at paras 251-52.
289 See AltaGas, *Application for Review and Variance, Generic Cost of Capital Decision 2011-474* (6 February 2012).
290 *Ibid* at paras 20-21.
291 *Ibid* at paras 23-24. See Alta Reg 546/1963.
292 *Ibid* at para 19.
293 *Ibid* at para 34.

d. Decision

The AUC determined that the appropriate return on equity for 2011 and 2012 is 8.75 percent. The AUC held that due to credit volatility, a formula approach to calculating return on equity for future years was inappropriate at the time. The AUC also held that stranded assets should be removed from the rate base of utilities.

AltaGas' application for review and variance had not yet been heard at the time of writing this article.

VII. STANDING AND PARTICIPANT FUNDING

A. ALBERTA COURT OF APPEAL

1. *VISSCHER V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*

In the decision of *Visscher v. Alberta (Energy Resources Conservation Board)*,[294] the Court of Appeal considered whether standing should have been granted by the ERCB to adjoining landowners in an application to expand an existing facility. This decision confirms that where an application is brought to expand a facility, the ERCB will not grant standing in the absence of fresh impacts from the expansion beyond those already occasioned by the existing facility.

a. Application

This decision considered two applications brought by landowners seeking standing before the ERCB in relation to applications to the ERCB to expand existing facilities on adjoining lands.

b. Background

This decision involved two applications. The first application was brought by Provident Energy, which operates an existing facility that stores hydrocarbons in 11 underground caverns, to store hydrocarbons in a new twelfth cavern.[295] The second application was brought by Williams Energy to install a compressor and related components in relation to the Butane/Butylene Mix Value Upgrade Project at its existing Olefins Fractionation and Storage Complex.[296]

The ERCB confirmed that the test for standing involves two branches. First, the ERCB must determine whether the "right or interest being asserted by the person is one known to law. The second branch asks whether the Board has information which shows that the

294 2011 ABCA 209, AJ no 737 (QL) [*Visscher*].
295 *Ibid* at para 2.
296 *Ibid*.

application before the Board may directly and adversely affect those interests or rights."[297] The first branch is a legal test, the second is a factual test.

The ERCB approved both applications.

c. Key Findings

There was no dispute that the applicants, as adjoining landowners, met the first part of the test. The question was whether the ERCB made an error of law in determining that only incremental impacts related to the applications to expand existing facilities were to be considered.[298]

The Court stated that in relation to the Provident Energy application, the findings of the ERCB were that there would be no increased impact in expanding the facility.[299] As a result, granting the adjoining landowners standing would equate to a reexamination of the permit originally given for the existing facility. Noting that the ERCB is only required to consider the application before it, and is not required to reexamine previous applications, the Court determined that the ERCB was justified in denying standing to the landowners.[300]

Similarly, the ERCB determined that there would be no impact related to expansion under the Williams Energy application and, as a result, the ERCB was justified in denying the landowners standing.[301]

d. Decision

The applications for leave to appeal were dismissed.

2. *KELLY V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*

The decision in *Kelly v. Alberta (Energy Resources Conservation Board)*[302] considered whether a person who resides outside the Emergency Planning Zone (EPZ), but within the zone where a potential exists for hydrogen sulfide (H_2S) levels of 10 parts per million, is potentially directly and adversely affected as a matter of law, and as a result, entitled to standing. This decision is of interest because it demonstrates that a party residing beyond the EPZ for a sour gas well may be considered to be directly and adversely affected by the well if there is evidence that they could be exposed to some concentration of H_2S.

297 *Ibid* at para 3, citing *Dene Tha' First Nation v Alberta (Energy and Utilities Board)*, 2005 ABCA 68, 363 AR 234.
298 *Visscher*, *ibid*.
299 *Ibid* at para 6.
300 *Ibid*.
301 *Ibid* at para 7.
302 2011 ABCA 325, 515 AR 201 [*Kelly 2011*].

a. Background

The respondent Daylight Energy applied to the ERCB to drill a sour gas well. The appellants opposed the drilling of the well. Daylight Energy asked the ERCB to disregard the objection of the appellants on the basis that they lacked standing.[303]

The appellants were located outside the EPZ and the Protective Action Zone for the well. Despite this, based on computer modeling carried out to meet then current ERCB requirements, it was determined that detectable levels of H_2S from the well could reach their properties and potentially trigger their evacuation.[304] As a result, the appellants argued that they were potentially "adversely affected" within the meaning of section 26(2) of the *Energy Resources Conservation Act*[305] and should be granted standing before the ERCB.[306] The appellants also argued that because of health concerns, including asthma, they were adversely affected by the well because of their increased sensitivity to H_2S.

The ERCB determined that the appellants did not demonstrate that they would be adversely affected by the well, stating that the risk of evacuation was not an adverse effect.[307] The ERCB said that exposure to gas was an adverse effect, and evacuation was merely a method of attempting to remediate that problem.[308] Also, the ERCB stated that there was insufficient evidence to demonstrate that the appellants were adversely affected because of their heightened sensitivity to H_2S.[309] As a result, their application for standing was dismissed.[310]

b. Key Findings

The Court considered the ERCB's findings that the distance of the appellants' property from the well and the level of risk posed to those appellants were legitimate considerations that were taken into account in determining standing. The Court also stated that the possible deficiencies identified by the appellants in the evacuation plans did not demonstrate that the appellants were adversely affected.[311]

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303 *Ibid* at para 2.
304 *Ibid* at paras 4-6.
305 RSA 2000, c E-10, which states that
> if it appears to the Board that its decision on an application may directly and adversely affect the rights of a person, the Board shall give the person
> (a) notice of the application,
> (b) a reasonable opportunity of learning the facts bearing on the application and presented to the Board by the applicant and other parties to the application,
> (c) a reasonable opportunity to furnish evidence relevant to the application or in contradiction or explanation of the facts or allegations in the application,
> (d) if the person will not have a fair opportunity to contradict or explain the facts or allegations in the application without cross-examination of the person presenting the application, an opportunity of cross-examination in the presence of the Board or its examiners, and
> (e) an adequate opportunity of making representations by way of argument to the Board or its examiners.

306 *Kelly 2011*, *supra* note 302 at para 7.
307 *Ibid* at para 11.
308 *Ibid*.
309 *Ibid*.
310 *Ibid*.
311 *Ibid* at para 21.

However, the Court found that the ERCB's analysis did not withstand scrutiny on the reasonableness standard because it lacked transparency and intelligibility. The Court stated that the ERCB's requirement that the appellants demonstrate heightened sensitivity to H_2S was inconsistent with past decisions which determined that the applicants did not have to demonstrate that they were affected to a greater degree than the general public.[312]

The Court also stated the ERCB's findings that evacuation plans are merely precautionary and preparatory did not answer the question of whether the appellants would be adversely impacted if an emergency did occur, and the corresponding level of risk.[313] The Court also held that the ERCB's suggestion that evacuation is not an adverse effect ignored the fact that such a plan is predicated on the existence of a lurking risk that is in itself adverse.[314]

The Court determined that a person residing within the tertiary zone of a sour gas well is eligible for standing before the ERCB. Whether a particular applicant residing in that zone would be granted standing depends on a finding by the ERCB that they are directly and adversely affected, but the decision of the ERCB to deny these applicants standing was not made in the context of a reasonable meaning of "directly and adversely affected."[315]

c. Decision

The appeal was allowed and the matter was remitted to the ERCB for reconsideration.

3. *KELLY V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*

In the decision of *Kelly v. Alberta (Energy Resources Conservation Board),*[316] the Court of Appeal was asked to determine whether the appellants, as owners of land in the vicinity of a well, were entitled to costs for their intervention in a hearing before the ERCB. This decision indicates that cost awards may be granted where there is a potential adverse impact on the use and occupation of land and that the absence of any actual adverse effect does not in and of itself disentitle an applicant to costs.

a. Background

The appellants in this decision were owners of lands in the vicinity of a sour gas well who applied for intervener status to appear before the ERCB. The ERCB denied the appellants standing, holding that they were not directly and adversely affected.[317] That decision was appealed to the Court. The appeal was allowed and the Court directed the ERCB to "conduct a rehearing of the well licence applications, at which rehearing the appellants would have standing."[318]

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312 *Ibid* at paras 22, 25.
313 *Ibid* at para 23.
314 *Ibid* at paras 23-24.
315 *Ibid* at para 27.
316 2012 ABCA 19, 519 AR 284 [*Kelly 2012*].
317 *Ibid* at para 2.
318 *Ibid*.

The rehearing occurred and the licence to operate the well was confirmed. The appellants subsequently applied for an award of costs to defray expenses related to their intervention as "local interveners" under section 28 of the *Energy Resources Conservation Act*.[319]

The ERCB determined that the appellants did not qualify as local interveners because they did not establish the requisite interest in or right to occupy the land, or provide reasonable grounds for believing that such land may be directly and adversely affected. As a result, the ERCB stated that they were not entitled to costs.[320]

b. Key Findings

The Court stated that costs decisions of the ERCB will only be disturbed if they contain an unreasonable decision on a point of law.[321] The Court found that the decisions of the ERCB in this costs award lacked transparency because it was not clear how much weight was placed on the perceived need for physical damage to the property.[322] The Court indicated that it viewed the ERCB's decision not to award costs to be based on the ERCB's opinion that physical damage to land was required to award costs.[323] The Court disagreed with this opinion, holding that potential interference with the use and occupation of land was sufficient.[324]

Also, the Court held that it appeared the ERCB made the costs award dependant on the outcome of the hearing, awarding costs to the perceived winners in the application (and since the interveners "lost," they were awarded no costs). The Court stated that it was unreasonable for the ERCB to award costs on this basis, since one of the purposes of a hearing is to gain public input into proposed developments.[325] While discretion is afforded to the ERCB in determining the amount of costs to be awarded, the Court stated that "the actual outcome of the hearing, and the absence, with hindsight, of any actual adverse effect does not of itself disentitle an applicant to costs."[326]

c. Decision

The Court allowed the appeal and remitted the application for costs back to the ERCB for reconsideration.

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319 *Supra* note 305. See *Kelly 2012*, *ibid* at paras 3-4.
320 *Kelly 2012*, *ibid* at para 5.
321 *Ibid* at para 22.
322 *Ibid* at para 24.
323 *Ibid* at paras 25-26.
324 *Ibid* at para 24.
325 *Ibid* at para 31.
326 *Ibid* at para 37.

B. ENERGY RESOURCES CONSERVATION BOARD

1. ENERGY COST ORDER 2012-001: *CONOCOPHILLIPS CANADA OPERATIONS LTD., APPLICATIONS FOR A CRUDE OIL WELL AND ASSOCIATED PIPELINE, PEMBINA FIELDS*

In the underlying application, the ERCB considered an application by ConocoPhillips Canada Operations Ltd. (ConocoPhillips) for a licence to drill a critical sour gas well and construct an oil pipeline.[327] This decision is notable as it demonstrates that the ERCB will consider intervener cost recovery for work done prior to the issuance of a notice of hearing and suggests that a party with standing will be entitled to recover their costs even where an application does not proceed to a hearing. Also of note in the decision is the ERCB's criticism of the applicant for withdrawing its application in a manner inconsistent with the spirit of common courtesy to landowners expected of applicants while conducting their participant involvement program.

a. Application

ConocoPhillips brought an application before the ERCB for licences to construct and operate a sour gas well in addition to an oil pipeline.

b. Background

The MacKenzies objected to the applications and were found to have standing in the matter.[328] Shortly after their objection was noted, ConocoPhillips withdrew its applications.[329] The MacKenzies claimed costs in relation to preparing for the hearing of the applications. The MacKenzies submitted that had the application proceeded, their lands may have been significantly affected.[330]

ConocoPhillips submitted that the costs claimed should be denied because it was not common practice for the ERCB to award costs to parties that were incurred prior to a notice of hearing being issued.[331] ConocoPhillips took the position that the costs claimed were not necessary because they did not contribute to a better understanding of the issues before the ERCB.[332]

c. Key Findings

The ERCB made note of the fact that the applications were withdrawn by ConocoPhillips immediately upon being informed that the project would be the subject of a hearing. No reason was provided for the withdrawal. The ERCB noted that this resulted in the "interveners hav[ing] committed considerable time and effort to voicing and preparing their

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327 ERCB, *ConocoPhillips Canada Operations Ltd, Applications for a Crude Oil Well and Associated Pipeline, Pembina Field — Cost Awards* (17 January 2012), Energy Cost Order 2012-001.
328 *Ibid* at para 18.
329 *Ibid* at para 20.
330 *Ibid* at paras 17, 19.
331 *Ibid* at para 14.
332 *Ibid* at para 16.

objections, and hav[ing] incurred expenses" to oppose an application that did not go forward.[333]

The ERCB indicated that it expects applicants to fully consider various options in relation to a project and to be committed to a project prior to engaging the Board's hearing process. The ERCB noted that the lack of commitment to this project demonstrated disregard for stakeholders and showed a lack of courtesy to landowners engaged in the participant involvement program.[334]

The ERCB noted that the costs claimed by the MacKenzies were related to preparation for the hearing and as a result, the claims were legitimate.[335]

d. Decision

ConocoPhillips was ordered to pay the intervener's costs.

C. ALBERTA UTILITIES COMMISSION

1. DECISION 2011-464*: FEDERATION OF ALBERTA NATURALISTS AND GRASSLAND NATURALISTS, DECISION ON PRELIMINARY QUESTION, REVIEW AND VARIANCE DECISION 2011-329, NATURENER ENERGY CANADA INC., 162-MW WILD ROSE 2 WIND POWER PLANT AND ASSOCIATED EAGLE BUTTE SUBSTATION*

This decision[336] considered whether the review and variance of a previous decision of the AUC should be undertaken at the request of a party that was not afforded standing in the initial application. This decision indicates that where a party has not been granted standing in an initial application, it is not at liberty to request a review and variance where no evidence has been provided to indicate that standing should have been granted in the initial application.

a. Background

The AUC previously considered an application by NaturEner to construct and operate a power plant and substation in relation to a wind farm and approved the projects.[337]

A joint application was subsequently brought by the Federation of Alberta Naturalists and Society of Grassland Naturalists to review and vary the decision. At the initial hearing, these groups were provided an opportunity to provide statements, but were not found to hold rights or interests that permitted them to be involved as interveners at the hearing.[338]

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333 *Ibid* at para 20.
334 *Ibid*.
335 *Ibid* at para 23.
336 AUC, *Federation of Alberta Naturalists and Grassland Naturalists, Decision on Preliminary Question, Review and Variance of Alberta Utilities Commission Decision 2011-329, NaturEner Energy Canada Inc, 162-MW Wild Rose 2 Wind Power Plant and Associated Eagle Butte Substation* (24 November 2011), AUC Decision 2011-464 [AUC Decision 2011-464].
337 *Ibid* at para 3.
338 *Ibid* at para 4.

b. Key Findings

The AUC determined that no information was filed by these groups at the time of the initial application or afterward demonstrating that they had a legal right or interest known to law with respect to the area of the proposed project.[339]

The AUC noted that case law established restrictive guidelines for tribunals to vary their decisions to ensure and preserve the integrity of tribunal decisions.[340] The AUC did not consider the application for review and variance to fall within these guidelines because the groups were not granted standing to participate as interveners in the original proceeding.[341] As a result, the AUC determined that these groups were not entitled to request a review and variance.[342]

c. Decision

The application for review and variance was denied.

VIII. ADMINISTRATIVE LAW

A. ALBERTA COURT OF APPEAL

1. *INTER PIPELINE FUND V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*

The decision in *Inter Pipeline Fund v. Alberta (Energy Resources Conservation Board)*[343] considered whether the ERCB adequately explained its assessment of critical evidence submitted by a project proponent and whether the cumulative effect of the ERCB's decision denied interveners procedural fairness. This decision suggests that the ERCB must clearly explain its reasons in weighing important evidence before it and provide parties an opportunity to test that evidence relevant to the ERCB's decision.

a. Application

The intervener sought leave to appeal a decision of the ERCB which approved the application of Taylor Processing Inc. (Taylor) to develop a co-streaming project at its existing Harmattan gas plant on the grounds that the interveners were not provided full and sufficient answers regarding critical evidence and were, therefore, denied procedural fairness by the ERCB.

339 *Ibid* at para 10.
340 *Ibid* at para 12, citing *AltaGas Utilities v Alberta (Energy and Utilities Board)*, 2008 ABCA 46, [2008] AJ no 112 (QL).
341 AUC Decision 2011-464, *ibid*.
342 *Ibid* at para 11.
343 2011 ABCA 242, [2011] AJ no 878 (QL).

b. Background

The ERCB issued a Notice of Hearing establishing a procedural timetable leading up to the hearing of Taylor's application. The schedule was modified to allow for a process that permitted interested parties to submit written information requests to Taylor regarding relevant "evidence, documents or other materials," and required Taylor to provide a "full and adequate response to each question."[344]

Many of the responses provided by Taylor were very brief or simply indicated that Taylor did not have the information requested addressing specific questions. Taylor relied on a report prepared by Ziff Energy Group regarding critical issues related to the project, such as the sufficiency of gas supply to feed a power plant. While Taylor was able to access additional information from Ziff, questions from interveners concerning Ziff's forecasts also received the response that Taylor did not have the requested information.[345]

Despite the responses from Taylor, the ERCB determined that it had adequate information to proceed to a hearing, and indicated that "the parties could pursue any deficiencies in Taylor's responses in the course of cross-examining [the] witnesses [presented by Taylor]."[346]

Shortly before the hearing, Taylor provided the ERCB with additional evidence relating to long-term gas supply in Alberta that included little analysis or explanation for its forecast of gas supply. This information was not available to the interveners when they prepared their information requests.[347]

Within days of the hearing and after the parties had provided written submissions to the ERCB, Taylor advised it would not be relying on the Ziff report or calling expert evidence on the issue of gas supply. Instead, it relied on industry forecasts including one completed by TransCanada Pipeline (TCPL) prepared some time earlier and apparently as promotional information for potential investors.[348] As a result, there was no opportunity for interveners to challenge the underlying analysis or conclusions that there would be adequate gas supply to support the gas plant.[349]

Taylor failed to submit evidence related to adequate gas flow. Therefore, the interveners were the only party to present such evidence, in the form of a report prepared by Purvin & Gertz Inc.[350] The ERCB indicated that it considered gas flows to be somewhere between those projected in the TCPL document and in the Purvin & Gertz report.[351]

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344 *Ibid* at para 2.
345 *Ibid* at para 5.
346 *Ibid* at para 7.
347 *Ibid* at para 9.
348 *Ibid* at para 8.
349 *Ibid* at para 10.
350 *Ibid* at para 11.
351 *Ibid* at para 15.

The interveners appealed the ERCB's decision on the basis that the ERCB misconstrued the evidence and provided inadequate reasons.[352] The interveners claimed that they were entitled to a full explanation for the determination that the TCPL report, prepared for investors and not tested on cross-examination, was entitled to the same weight as the Purvin & Gertz report. The interveners also sought leave to appeal the ERCB's decision on the basis of a breach of procedural fairness. The parties argued that the ERCB permitted Taylor to withhold evidence prior to and during the course of the hearing, undermining the interveners' rights to procedural fairness.[353]

c. Key Findings

The Court of Appeal stated that it was seriously arguable that where evidence submitted to the ERCB was "contradicted by other expert evidence, and supported by an expert whose evidence was tested but not significantly compromised on cross-examination, the opposing party is entitled to a full explanation of the relevant findings that led the Board to decide the issue."[354] In this case, it appeared to the Court that the reports of TCPL and the Purvin & Gertz were afforded the same weight despite obvious deficiencies in the TCPL report. The Court determined that this raised a serious question of law and the interveners met the criteria for leave to appeal to the Court on that point.[355]

The Court also determined that the test for leave to appeal on procedural grounds was met.[356] Having decided to waive the information request process requirements on the basis that there would be an opportunity for cross-examination at the hearing, the ERCB then precluded effective cross-examination on critical aspects of Taylor's evidence by condoning Taylor's tactic of not providing experts. This indicated to the Court that the interveners may have been denied procedural fairness when participating in this application.[357]

d. Decision

The Court granted leave to appeal on the issues of whether the ERCB gave adequate reasons explaining its assessment of the critical evidence and whether the ERCB breached its duty to provide procedural fairness to the interveners.

352 *Ibid* at para 14.
353 *Ibid* at paras 14, 19.
354 *Ibid* at para 17.
355 *Ibid* at paras 16-18.
356 *Ibid* at para 25.
357 *Ibid* at paras 19-24.

IX. LEGISLATIVE DEVELOPMENTS

A. FEDERAL

1. BILL C-38, *JOBS, GROWTH AND LONG-TERM PROSPERITY ACT*

Bill C-38[358] was tabled 26 April 2012 in the House of Commons. This Bill contained several significant changes to federal environmental legislation, including the amendment of a number of key pieces of environmental legislation and the replacement of the *Canadian Environmental Assessment Act*[359] with the *Canadian Environmental Assessment Act, 2012*.[360] The *CEAA 2012* provides time limits for certain review processes, greater coordination between different government agencies, and reduced duplication of application materials.

Under the *CEAA 2012*, only projects designated by regulation or ministerial order will be subject to assessment.[361] The former approach of conducting reviews where a proposed project is considered to "trigger" the *Act* will no longer be used.

There will no longer be "comprehensive studies" under the new *Act*, although projects may still be referred to a review panel. The Minister of the Environment (the Minister) may authorize "equivalent assessments" to be conducted by a responsible federal authority, provincial government agency, foreign government, or other approved authority.[362]

To speed up the regulatory process, the new *Act* sets time limits that the Minister must follow in rendering its decision.[363] For assessments conducted by the Canadian Environmental Assessment Agency, the assessment must be completed in 365 days. For assessments carried out by review panels, the time limit is 24 months. These time limits are subject to extensions provided by the Minister or federal Cabinet, depending on the circumstances.

Bill C-38 also permits assessments to be performed in relation to areas under federal jurisdiction: fish, aquatic species, migratory birds, projects on federal lands, and projects that affect Aboriginal peoples.[364] This change will have minimal effect on projects in Canada's northern territories, which are subject to different federal environmental assessment regimes resulting from land claims agreements. The Bill also provides for increased enforcement and penalty provisions.[365]

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358 Bill C-38, *An Act to implement certain provisions of the budget tabled in Parliament on March 29, 2012 and other measures*, 1st Sess, 41st Parl, 2012 (assented to 29 June 2012), SC 2012 c 19 [Bill C-38].

359 SC 1992, c 37 [*CEAA*].

360 The full text of the *Canadian Environmental Assessment Act, 2012* [*CEAA 2012*] is found in section 52 of Bill C-38, *supra* note 358. Section 66 of Bill C-38 repeals the *CEAA*.

361 *CEAA 2012, ibid*, s 13.

362 *Ibid*, s 37.

363 *Ibid*, ss 27(2)-(4)

364 *Ibid*, s 5(1).

365 *Ibid*, ss 89-102.

Bill C-38 also provides for significant changes to the *NEB Act*,[366] the *Canadian Oil and Gas Operations Act*,[367] *the Nuclear Safety and Control Act*,[368] the *Fisheries Act*,[369] the *Canadian Environmental Protection Act, 1999*,[370] and the *Species at Risk Act*.[371] The changes made by Bill C-38 were designed to streamline and speed up the regulatory approval process for projects subject to federal review.

The *NEB Act* has been amended by the Bill to give the federal Cabinet final say on whether major pipeline projects are approved. Also, the Chairperson of the NEB is authorized to deal with an application in any manner he or she considers appropriate to ensure that time limits are met and they are entitled to issue directives to members authorized to deal with the application to ensure that applications are heard in a timely manner.[372] Under section 74, the NEB is required to deal with applications as expeditiously as possible, but specifies that any time limit set out in the *Act* must be met. The NEB is required to submit its final report and recommendations to the Governor in Council within 15 months from the date the NEB receives a complete application from a proponent.[373] The Governor in Council is required to make a decision regarding the issuance of a certificate within three months of receiving the NEB's report and recommendations, and if the Governor in Council approves the issuance of a certificate, the NEB is required to provide that certificate within seven days.[374] All these time limits are subject to extensions provided by the Minister or federal Cabinet, depending on the circumstances.

The amendments made by Bill C-38 to the *NEB Act* change the standing requirements in relation to the Board from "any interested person" (as seen in section 53 of the old *Act*) to any person who "is directly affected by the granting or refusing of the application," although the Board has the discretion to also hear from any person who has "relevant information or expertise."[375] The Bill also imposes tight time limits for those seeking to challenge the approval of major pipeline projects and severely limits the scope of judicial oversight of decisions of the Governor in Council approving major pipeline projects.[376]

Bill C-38 also amended the *Fisheries Act*, including authorizing the Governor in Council to enact regulations excluding certain waters from the prohibition on causing serious harm to fish and damaging or destroying fish habitat. Bill C-38 creates categories of fish habitat including commercial, recreational, and Aboriginal fisheries. A commercial fishery includes any fish harvested under the authority of a licence for the purpose of sale, trade, or barter. A recreational fishery includes any fish harvested under licence for personal use or sport. An Aboriginal fishery includes any fish harvested by an Aboriginal organization or any member of one and used as food or for subsistence, social, or ceremonial purposes.[377] These

366 *Supra* note 210.
367 RSC 1985, c O-7.
368 SC 1997, c 9.
369 RSC 1985, c F-14.
370 SC 1999, c 33 [*CEPA*].
371 SC 2002, c 29.
372 Bill C-38, *supra* note 358, s 71(2).
373 *Ibid*, s 83.
374 *Ibid*.
375 *Ibid*.
376 *Ibid*.
377 *Ibid*, s 133(3).

categories have replaced the former definition of "fish habitat" found in section 34 of the unamended *Act*. The amendments also impose minimum penalties for several offences relating to the harm or destruction of these fisheries.[378]

The amendments to *CEPA* and the *Species at Risk Act* allow the responsible Minister to set time limits for the issuance or denial of permits to dispose of wastes and engage in activities affecting listed species.[379]

Bill C-38 received royal assent on 29 June 2012.

2. THE *REDUCTION OF CARBON DIOXIDE EMISSIONS FROM COAL-FIRED GENERATION OF ELECTRICITY REGULATIONS*, PURSUANT TO THE *CANADIAN ENVIRONMENTAL PROTECTION ACT, 1999*

Initially proposed in August 2011, the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*[380] will set a stringent performance standard for new coal-fired units and those that have reached the end of their useful life. The objective of the regulations is to ensure transition away from high-emitting coal-fired electricity generation to low or non-emitting generation such as renewable energy, high efficiency natural gas, or thermal power with carbon capture and storage. The regulations will come into force on 1 July 2015.

B. ALBERTA

1. AMENDMENTS TO THE *ALBERTA LAND STEWARDSHIP ACT* WERE PASSED IN MAY 2011 AND THE *ALBERTA LAND STEWARDSHIP REGULATION* WAS PASSED 1 SEPTEMBER 2011

The amendments to the *Alberta Land Stewardship Act*[381] and the *Alberta Land Stewardship Regulation*[382] include clarification of the original intent of the legislation with a clear statement that the Government of Alberta must respect the property and other rights of individuals when taking action under the *Act*.[383] Also, the *Act* now articulates that any existing rights to compensation are not to be limited and that all existing appeal provisions in Alberta legislation are to be respected.[384]

Amendments also indicate that the government is required to conduct public consultation and present draft regional plans to the legislature, and also establish new review provisions. These include:

- Permitting any party directly and adversely affected by a regional plan to request a review of the plan;

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378 *Ibid*, s 144.
379 *Ibid*, ss 161, 163.
380 SOR/2012-167.
381 SA 2009, c A-26.8 [*ALSA*].
382 Alta Reg 179/2011.
383 See *Alberta Land Stewardship Amendment Act, 2011*, SA 2011, c 9.
384 *ALSA*, *supra* note 381, ss 2(3) (dealing with compensation), 9(3) (dealing with appeals).

- Allowing title holders to apply for the variance of a plan; and

- Allowing land owners to apply for compensation where their property or rights are infringed by a regional plan.[385]

Further amendments provide that a regional plan cannot change or cancel municipal development approvals where the development is underway or completed.[386]

The *Alberta Land Stewardship Regulation* provides further clarity for landowners concerning the implementation of regional plans under the Land-use Framework and specifies how landowners may apply for review, variance, or compensation in relation to the implementation of regional plans.[387]

2. THE *SPECIFIED GAS EMITTERS AMENDMENT REGULATION*, ENACTED PURSUANT TO THE *CLIMATE CHANGE AND EMISSIONS MANAGEMENT ACT*, CAME INTO FORCE ON 24 JUNE 2011

The amendments to the *Specified Gas Emitters Regulation*[388] include a new definition for "emission offset" and a change in fund credits.[389] This regulation is noteworthy because it enables proponents of carbon capture and sequestration projects to obtain additional emission offsets, provided certain new requirements are met.

Also, section 8(2) has been repealed and substituted with new language. Previously, this section stated that a fund credit of one tonne reduction in CO_2 would be obtained for each $15 contribution to the Climate Change and Emissions Management Fund. Now, this section states that "[t]he Minister may, by order, establish the amount of money that a person responsible must contribute to the Fund to obtain one fund credit equal to a one tonne reduction in emissions, expressed on a CO_2e basis."[390]

These amendments also provide for new requirements that must be met in order for geological sequestration of specified gas to constitute emission offsets.[391] These requirements enable an additional emission offset to be obtained for the capture of carbon dioxide where the same tonne of carbon dioxide is geologically sequestered, provided certain requirements specifying particular methods of capture, timing, and the location of gas sequestration are complied with.

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385 *Ibid*, ss 5 (public consultation and draft regional plans), 15.1(1) (variance), 19 (compensation), 19.1(1) (review).
386 *Ibid*, s 11(3).
387 *Alberta Land Stewardship Regulation*, *supra* note 382, ss 5-35.
388 *Supra* note 106.
389 See *Specified Gas Emitters Amendment Regulation*, Alta Reg 127/2011.
390 *Specified Gas Emitters Regulation*, *supra* note 106, s 8(2).
391 *Ibid*, s 7(1.1).

3. THE *LAND ASSEMBLY PROJECT AREA AMENDMENT ACT, 2011* CAME INTO FORCE ON 8 DECEMBER 2011

This amendment[392] was designed to address confusion about what kinds of projects fall under the *Land Assembly Project Area Act*,[393] concerns about whether Albertans get fair compensation and access to the *Expropriation Act*,[394] concerns about access to the courts for compensation and to seek enforcement orders, and concerns about penalties under the *Act*.

These areas have been addressed in the amendments by:

- Providing landowners the option to trigger expropriation of their lands, making it clear that landowners have the option to sell their land to the government and then lease it back until the infrastructure project begins;[395]
- Providing a clear explanation of the types of major transportation or water projects covered by the *Act*;[396]
- Making it clear that this legislation does not override the *Expropriation Act*;[397]
- Removing all suggestions that an Albertan could receive a jail sentence for violating the *Act*;[398] and
- Providing for enhanced access to the courts under the *Act*.[399]

C. BRITISH COLUMBIA

1. AMENDMENTS TO THE *DRILLING AND PRODUCTION REGULATION*, ENACTED PURSUANT TO THE *OIL AND GAS ACTIVITIES ACT*, CAME INTO FORCE 1 JANUARY 2012

Changes to the *Drilling and Production Regulation*[400] require the public disclosure of ingredients used for hydraulic fracturing in the province.

A registry system was created under the new amendments that includes a database of the ingredients used to support natural gas extraction. By law, a list of ingredients used must be registered within 30 days of the completion of operations permitting the well to produce gas.[401]

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392 *Land Assembly Project Area Amendment Act, 2011*, SA 2011, c 21 [*LAPAA Amendment*].
393 SA 2009, c L-2.5 [*LAPAA*].
394 RSA 2000, c E-13.
395 *LAPAA Amendment*, *supra* note 392, s 5.
396 *Ibid*, s 4.
397 *Ibid*, s 5.
398 *Ibid*, s 9. Section 17(1) of the *LAPAA*, *supra* note 393 now provides that a person or corporation who contravenes an enforcement order is guilty of an offence and liable to a fine.
399 *Ibid*, ss 5, 7.
400 BC Reg 282/2010.
401 *Ibid*, s 37.

This amendment was designed to increase transparency of hydraulic fracturing processes employed in British Columbia.

X. DEVELOPMENTS IN POLICY, DIRECTIVES, AND GUIDELINES

A. FEDERAL

1. THE GOVERNMENTS OF CANADA AND ALBERTA RELEASED THE *JOINT CANADA-ALBERTA IMPLEMENTATION PLAN FOR OIL SANDS MONITORING*

The Government of Canada and the Government of Alberta are working together on a phased and adaptive approach to monitoring oil sands development within the province and have released the *Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring*.[402] The expansion of oil sands has led to increased need to develop a better understanding of the potential cumulative environmental effects of these operations.

The *Joint Plan* is designed to strengthen environmental monitoring programs for air, water, land, and biodiversity in the oil sands region. The goal is to improve knowledge of the state of the environment and an enhanced understanding of cumulative effects and environmental change, including future impacts arising from numerous operations occurring in the oil sands area.[403]

The intention of the *Joint Plan* is to enhance monitoring in the region over the next three years to ensure that the "installation of necessary infrastructure, incremental enhancement of activities and appropriate integration with existing monitoring activities in the region" is carefully supervised.[404]

By the time the *Joint Plan* is fully implemented in 2015, it is anticipated that the number of sampling sites will be increased over a larger area, the number and types of parameters being sampled will increase, the frequency of sampling will increase, methodologies utilized in sampling will be improved, and an integrated, open data management program will be created.[405]

2. THE NATIONAL ROUND TABLE ON THE ENVIRONMENT AND THE ECONOMY (NRTEE) RECENTLY OUTLINED THE STEPS THAT CANADA SHOULD TAKE TO SUSTAIN WATER USE BY NUMEROUS INDUSTRIES, INCLUDING MINING, OIL AND GAS, AND THERMAL ELECTRICITY GENERATION IN ITS REPORT *CHARTING A COURSE*

Recognizing that the natural resource sectors are and will continue to be the most significant users of water in Canada, the NRTEE has outlined a number of steps to be taken

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402 Government of Canada & Government of Alberta, *Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring* (Ottawa: Public Works and Government Services Canada, 2012), online: Government of Canada <http://www.ec.gc.ca/pollution/EACB8951-1ED0-4CBB-A6C9-84EE3467B211/Final%20OS%20 Plan.pdf> [*Joint Plan*].

403 *Ibid* at 1-2.

404 *Ibid* at 2.

405 *Ibid* at 8, 15.

to sustain water use in numerous industries, including mining, oil and gas, and thermal electricity generation.[406]

These steps stress strategies that address the goals of water conservation and water efficiency to ensure ecosystem protection, allow jurisdictions to be better prepared for and avoid water shortages, and to address the best management practices for future uncertainty concerning water supplies.

This policy suggests adopting new economic instruments and voluntary initiatives to improve water conservation and water efficiency. It is suggested that water charges and tradable water permits be developed to provoke current regulatory approaches to adopt water-conserving technologies.[407] The policy also suggests that by utilizing voluntary initiatives such as measuring and reporting water use and improving transparency of industrial water management, industry's "social licence" to operate may be supported.[408]

The policy recommends adopting a method for pricing water on a volumetric basis to support the initiative outlined in the NRTEE's report. It is also suggested that the federal, provincial, and territorial governments collaborate to develop and publish national water-use forecasts that be updated on a regular basis.[409]

Of note, the NRTEE was cancelled in the recent federal budget.[410]

B. ALBERTA

1. THE ALBERTA GOVERNMENT ANNOUNCED THE CREATION OF A CRITICAL TRANSMISSION REVIEW COMMITTEE

In November 2011, the Government of Alberta struck a committee to review issues related to the state of Alberta's electrical transmission system.[411]

Specifically, the committee was charged with "examining the reasonableness of the Alberta Electric System Operator forecasts, its selection of High Voltage Direct Current (HVDC) technology, and the timing of any required north-south transmission reinforcement."[412] After seeking input from industry and community stakeholders, the committee released its conclusions in a report in February 2012.

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406 NRTEE, *Charting a Course: Sustainable Water Use By Canada's Natural Resource Sectors* (Ottawa: National Round Table on the Environment and the Economy, 2011), online: NRTEE <http://nrtee-trnee.ca/wp-content/uploads/2011/11/charting-a-course-eng.pdf>.

407 *Ibid* at 19.

408 *Ibid* at 20.

409 *Ibid* at 22.

410 See *Jobs, Growth and Long-term Prosperity: Economic Action Plan 2012* (Ottawa: Public Works and Government Services Canada, 2012) at 218, online: Government of Canada <http://www.budget.gc.ca/2012/plan/pdf/Plan2012-eng.pdf>.

411 *Powering Our Economy — Critical Transmission Review Committee Report* (February 2012), online: Centre for Energy <http://www.centreforenergy.com/Documents/EnergyStrategies/AB-CTRCPoweringOurEconomy.pdf>.

412 *Ibid* at 2.

The committee reached the following conclusions:

1. The committee finds that the AESO's economic, load and generation forecasts for Alberta are reasonable.

2. The committee agrees that the AESO's recommendation to proceed with the development of two 500 kV transmission lines is reasonable.

3. The committee has determined that the AESO's decision to use HVDC technology is reasonable.

4. The committee finds it reasonable for the Alberta Government to proceed with the development of two 500 kV HVDC transmission lines as soon as possible.

5. The committee recommends the government amend the Electric Statutes Amendment Act, 2009 legislation.

6. The committee understands that there will be rate increases associated with the development of north-south transmission system reinforcement and recommends the AUC consider options that will mitigate the impact on consumers.

7. The committee encourages the use of competitive procurement processes for future critical transmission infrastructure projects.[413]

2. THE ALBERTA GOVERNMENT HAS PROPOSED TO CREATE A SINGLE REGULATOR FOR THE PROVINCE'S ENERGY SECTOR AND PRODUCED A DISCUSSION DOCUMENT, *ENHANCING ASSURANCE: DEVELOPING AN INTEGRATED ENERGY RESOURCE REGULATOR*, IN RELATION TO THE PROPOSAL

This document was the culmination of a lengthy process in which the Regulatory Enhancement Task Force undertook three rounds of engagement with stakeholders and First Nations.[414]

Participants identified a number of ways in which Alberta's current regulatory regime could be improved. They indicated that a simpler system for all stakeholders that is more transparent, easier to navigate, and utilizes a consistent set of processes was of critical importance.[415] The participants also indicated that policies need to be articulated more clearly so that they may be applied consistently when decisions are made about proposed energy projects.[416] It was also stressed that clear expectations on industry regarding public safety, environmental performance, resource conservation, and accountability are crucial to enhancing Alberta's regulatory system.[417]

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413 *Ibid* at 3.
414 Government of Alberta, *Enhancing Assurance: Developing an Integrated Energy Resource Regulator* (Edmonton: Government of Alberta, 2010), online: Alberta Energy <http://www.energy.alberta.ca/Org/pdfs/REPEnhancingAssuranceIntegratedRegulator.pdf>.
415 *Ibid* at 3.
416 *Ibid*.
417 *Ibid*.

Considering these concerns, it was suggested by the Task Force that project review and authorization, compliance monitoring, enforcement, facilities abandonment, and site reclamation or remediation should be regulated by a single regulatory body for the energy sector. It is suggested that a single regulator will provide consistency, clarity, efficiency, and effectiveness to the regulation of energy activities in Alberta.[418]

3. ALBERTA ENVIRONMENT AND THE MACKENZIE VALLEY ENVIRONMENTAL IMPACT REVIEW BOARD SIGNED THE "MEMORANDUM OF UNDERSTANDING REGARDING MAJOR DEVELOPMENT PROJECTS HAVING TRANSBOUNDARY IMPACTS" IN NOVEMBER 2011

This agreement[419] outlines notification requirements and information sharing commitments between the two authorities where environmental assessments have the potential to impact lands within the authority of each.

The memorandum stipulates that each authority will advise its counterpart of any project that may impact the environment under its jurisdiction and will share information about such impacts. Also, the memorandum determines the manner in which each authority will provide relevant information to its counter-part and requires each party to share descriptions of current regulatory processes in their respective jurisdictions.

The memorandum expires on 31 December 2015.

4. BULLETIN 2012-03: *GOVERNMENT OF ALBERTA REQUEST REGARDING ELECTRICITY RATES*

The Government of Alberta requested that the AUC freeze electricity rates pending a review of regulated electricity energy charges by an independent committee.[420]

The AUC has responded by agreeing to utilize a consistent approach to all relevant applications that are currently pending, but will not issue decisions that result in rate increases.[421] This approach will remain in effect until the Government of Alberta responds to the independent committee's recommendations.

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418 *Ibid*.

419 Memorandum between the Department of Environment for the Province of Alberta and the Mackenzie Valley Environmental Impact Review Board, "A Memorandum of Understanding Regarding Major Development Projects Having Transboundary Impacts" (November 2011).

420 AUC, Bulletin 2012-03, "Government of Alberta request regarding electricity rates" (13 March 2012), online: AUC <http://www.auc.ca/news-room/bulletins/BUlletins/2012/Bulletin%20202012-03.pdf>.

421 *Ibid*.

C. ENERGY RESOURCES CONSERVATION BOARD

1. THE *ENERGY RESOURCES CONSERVATION BOARD RULES OF PRACTICE*, ENACTED PURSUANT TO THE *ENERGY RESOURCES CONSERVATION ACT*

The ERCB released revised *Rules of Practice*,[422] which came into force on 15 June 2011. These *Rules* apply to all energy proceedings before the ERCB with the exception of appeals brought pursuant to section 27.2 of the *Energy Resources Conservation Act*.[423]

2. THE ERCB RELEASED A NEW EDITION OF DIRECTIVE 056: *ENERGY DEVELOPMENT APPLICATIONS AND SCHEDULES*

The new Directive 056[424] went into force on 26 September 2011. This Directive replaces IL 2001-05: "Construction of a Well Site Prior to the Issuance of a Well and Licence,"[425] as well as Bulletin 2007-35: "Clarification of Informational Letter (IL) 93-09: Oil and Gas Development Eastern Slopes (Southern Portion)."[426] Both of these documents are now rescinded.[427]

Changes to Directive 056 include updates regarding participant involvement, in particular that related to Aboriginal consultation; clarification of the requirements that must be met to obtain a licence prior to site preparation, construction, and operation; updates licencing requirements in relation to pipelines, facilities, and wells; and updates requirements of the ERCB in relation to environmental and technical reporting.[428]

3. THE ERCB RELEASED A REVISED EDITION OF DIRECTIVE 059: *WELL DRILLING AND COMPLETION DATA FILING REQUIREMENTS*

Key changes to this Directive[429] came into force 1 January 2012 and include the requirement of additional information on the creation and treatment of well event sequences with respect to the submission of data. There are also new submission requirements for reporting wells with preset surface casing, reporting well incident records for every operation requiring an electronic data submission, as well as directional survey reports.

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422 *Energy Resources Conservation Board Rules of Practice*, AR 98/2011.
423 *Supra* note 305.
424 *Supra* note 3.
425 ERCB, Informational Letter 2001-05, "Construction of a Well Site Prior to the Issuance of a Well License" (2001).
426 ERCB, Bulletin 2007-35, "Clarification of Informational Letter (IL) 93-09, Oil and Gas Development Eastern Slopes (Southern Portion)" (2007).
427 See ERCB, Bulletin 2011-25, "New Edition of *Directive 056* Issued and *Informational Letter (IL) 2001-5* and *Bulletin 2007-35* Rescinded" (1 September 2011), online: ERCB <http://www.ercb.ca/bulletins/Bulletin-2011-25.pdf>.
428 *Ibid*.
429 *Well Drilling and Completion Data Requirements*, ERCB Directive 059 (1 April 2012).

4. DIRECTIVE 065: *RESOURCES APPLICATIONS FOR OIL AND GAS RESERVOIRS* AND *BULLETIN 2011-29: CHANGES TO THE PROVINCE-WIDE FRAMEWORK FOR WELL SPACING FOR CONVENTIONAL AND UNCONVENTIONAL OIL AND GAS RESERVOIRS*

On 6 October 2011, the ERCB announced significant legislative changes to the *Oil and Gas Conservation Regulations*.[430]

These changes include the removal of well density controls for lower quality reservoirs such as coalbed methane (CBM) and shale gas reservoirs throughout the province. These changes remove the need for well spacing applications for CBM and shale gas, as well as conventional gas to the base of the Colorado Group. The only exception to the changes to well spacing applications will be in cases where special well spacing already exists.[431]

Also, the changes increase baseline well densities from one well per pool per standard drilling space unit to two wells per pool per standard drilling space unit for conventional gas reservoirs. The baseline well density changes are only applicable to those lands not subject to prior spacing approval and will not apply to a small section of lands identified in Schedule 13B of the *Regulations*. These changes will also not apply to CBM or shale gas.

The ERCB has also standardized target areas throughout the province. For conventional oil wells, the central target area will be a minimum of 100 metres from all section boundaries. Gas wells are to be divided into two categories. Gas wells located in Schedule 13B lands will have a target area of 150 metres from the south and west boundaries of a drilling space unit. Other gas wells will have a target area of 150 metres from all areas of the drilling space unit. Wells drilled in accordance with previous drilling standard units and target requirements that now conflict with the new well spacing requirements shall remain on target and will not be penalized for being off target.

Amendments to sections 4.040(1) – 4.040(3) of the *Regulations* provide that the ERCB will no longer require an application to change the target area of the drilling space units or reduce drilling space unit size. Amendments to section 4.050(1) of the *Regulations* permit a tract of land that is half the size of a normal drilling space unit to be considered an independent drilling space unit without having to apply to the ERCB. Tracts that have common mineral ownership to the east or west but are less than half the normal drilling space unit size will be joined with adjacent units without having to apply to the ERCB.

Also, Directive 065 eliminates the approval holder designation on those holdings that are established by well spacing applications. Former mandatory notice requirement have also been eliminated. A signed declaration of common ownership attached to the application is the only requirement.

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430 Alta Reg 151/1971. See ERCB, Bulletin 2011-29, "Changes to the Province-Wide Framework for Well Spacing for Conventional and Unconventional Oil and Gas Reservoirs" (6 October 2011), online: ERCB <http://www.ercb.ca/bulletins/Bulletin-2011-29.pdf> [Bulletin 2011-29]; *Resources Applications for Oil and Gas Reservoirs*, ERCB Directive 065 (14 March 2012) [Directive 065].

431 Bulletin 2011-29, *ibid*.

5. THE ERCB RELEASED A REVISED EDITION OF DIRECTIVE 060: *UPSTREAM PETROLEUM INDUSTRY FLARING, INCINERATING, AND VENTING*

This Directive[432] was updated 3 November 2011 to remove inconsistencies and improve clarity. Also, updates are aimed at eliminating or reducing flaring, venting, and incinerating in order to ensure Alberta Ambiant Air Quality Objectives[433] are met and, where required, to meet health and safety objectives.

Major changes include specifying when parties will be assessed under new amendments to section 7.040(1) of the *Oil and Gas Conservation Regulation*,[434] as well as newly added sections 7.035 of the *Oil and Gas Conservation Regulation* and 1.3 of the *Pipeline Regulation*.[435]

Changes also address flaring notification requirements, provide a new definition of "sour gas," remove reference to "public health" and "health impact" from the directive, and correct errors identified in the measurement and reporting requirements related to flaring, incinerating, and venting natural gas.

D. ALBERTA UTILITIES COMMISSION

1. THE AUC ANNOUNCED *BULLETIN 2011-25: CONSULTATION ON WIND-POWER GENERATION REGULATORY PERMITTING*

The AUC held these consultations on 12-13 December 2011 in Calgary.[436]

Topics discussed included:

- Existing approval processes and deficiencies identified specifically in relation to wind generation;
- Potential need to define limits to the initial term or extension term for construction approvals where there are competing proposals;
- The need to address transmission facilities in conjunction with generation applications; and
- Health impacts associated with shadow flicker and low frequency noise and adequacy of setbacks designed to address this.

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432 *Upstream Petroleum Industry Flaring, Incinerating, and Venting*, ERCB Directive 060 (3 November 2011).

433 Alberta Environment Air Policy Branch, "Alberta Ambient Air Quality Objectives and Guidelines Summary" (April 2011), online: Alberta Environment <http://www.environment.gov.ab.ca/info/library/5726.pdf>.

434 *Supra* note 430.

435 Alta Reg 91/2005.

436 AUC, Bulletin 2011-25, "Consultation on Wind-Power Generation Regulatory Permitting" (10 November 2011), online: AUC <http://www.auc.ab.ca/news-room/bulletins/Bulletins/2011/Bulletin%202011-25.pdf>.

E. MACKENZIE VALLEY LAND AND WATER REVIEW BOARD

1. THE MACKENZIE VALLEY LAND AND WATER REVIEW BOARD RELEASED *REVIEW OF THE ENVIRONMENTAL ASSESSMENT PROCESS IN THE MACKENZIE VALLEY*

To review the effectiveness of the environmental assessment process conducted by the Mackenzie Valley Land and Water Review Board, Stantec Consulting was hired to perform an independent audit of the process.[437]

Identifying a number of concerns regarding the length of this process, Stantec Consulting provided the following recommendations to improve efficiency:

- Develop practices for scoping environmental assessment in the Mackenzie Valley that recognize the interests of the parties and allow a timely environmental assessment;
- Develop a two-level environmental assessment process: a simpler more expedient process for developments requiring limited analysis, and a second process which provides for increased technical review;
- Develop increased guidance material for all parties. This would include updated process guidelines and more specific guidance on topics such as requirements for a project description, the scoping process, draft terms of reference, and formal submissions;
- Establish time limits for those phases of the environmental assessment process that the Review Board can control: formal submissions, conformity, technical review, report of the environmental assessment, and public comment periods;
- Develop a process for efficient referral of a development to environmental impact reviews during the scoping phase of the environmental assessment;
- Delegate more responsibility to the environmental assessment officers in implementing the environmental assessment process; and
- Undertake capacity development initiatives for the Review Board and staff.[438]

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437 Stantec Consulting, *Review of the Environmental Assessment Process in the Mackenzie Valley* (Yellowknife: Stantec Consulting, 2011), online: Mackenzie Valley Review Board <http://reviewboard.ca/upload/news/Stantec_MVEIRB_FINALReport%202011_1317659186.pdf>.

438 See *ibid* at ii.