RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO ENERGY LAWYERS

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This article highlights important legislative and regulatory developments of relevance to energy lawyers, including those involving electricity matters and related jurisprudence that arose between May 2012 and May 2013. The authors have reviewed a wide variety of subject areas, including examining decisions of key regulatory agencies such as the National Energy Board, the Canadian Environmental Assessment Agency, Alberta's Energy Resources Conservation Board, the Alberta Utilities Commission, the Alberta Surface Rights Board, the Ontario Energy Board, the Ontario Environmental Review Tribunal, and the World Trade Organization. Additionally, federal and provincial legislation and regulations of significance introduced during this period are canvassed.

Cet article souligne les développements législatifs et réglementaires importants qui sont d'intérêt pour les avocats travaillant dans le secteur énergétique, incluant ceux qui traitent d'affaires d'électricité et de la jurisprudence pertinente daujourd'hui. Les auteurs ont examiné un vaste nombre de domaines, incluant les décisions d'organismes clés de réglementation tels que l'Office national de l'énergie, l'Agence canadienne d'évaluation environnementale, le Alberta Energy Resources Conservation Board, la Alberta Utilities Commission, le Alberta Surface Rights Board, La Commission de l'énergie de l'Ontario, le Tribunal de l'environnement de l'Ontario et l'Organisation mondiale du commerce. De plus, les lois et règlements fédéraux et provinciaux d'importance présentés pendant cette période sont également revus.

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I. TRIBUNAL AND ADMINISTRATIVE BOARD DECISIONS

A. NATIONAL ENERGY BOARD

1. NOVA GAS TRANSMISSION LTD. — FACILITY[1]

On 6 July 2012, portions of the *Jobs, Growth and Long-term Prosperity Act* came into force, including legislative changes to the *National Energy Board Act*.[2] This was the first application following these legislative changes where the National Energy Board (NEB) submitted a report with its recommendation to the Governor in Council.

a. Application

On 14 October 2011, NOVA Gas Transmission Ltd. (NOVA) filed an application for a Certificate of Public Convenience and Necessity (the Certificate) with the NEB under section 52 of the *NEB Act* to construct and operate the Northwest Mainline Komie North Extension Project (individual or collective projects are hereinafter referred to as the Project or Projects). NOVA also applied for an order pursuant to section 58 of the *NEB Act* exempting it from the requirements under sections 31(c), 31(d), and 33 of the *NEB Act* "with respect to borrow pits for hydrostatic testing purposes, stockpile sites, contractor yards, construction camps and [a] meter station, and an associated access road."[3]

b. Background

The Project would extend and expand NOVA's Alberta System by approximately 130 kilometers of pipeline at two locations in northwestern Alberta and northeastern British Columbia. The Project would receive and transport natural gas supply from the Horn River Basin and Cordova Embayment areas of British Columbia. An estimated 79 kilometers of the proposed route was located contiguous to, or alongside, existing pipeline rights-of-way. Approximately 51 kilometers of the pipeline was proposed to be installed in non-contiguous rights-of-way.[4]

c. Key Findings and Decision

Pursuant to section 52(1) of the *NEB Act*, which requires the NEB to prepare a report along with the NEB's recommendation of whether or not a certificate should be issued for all or any portion of a pipeline, the assessed issues outside of the proposed Komie North Section were considered appropriate or acceptable.[5]

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1 *National Energy Board Report: NOVA Gas Transmission Ltd*, GH-001-2012 (January 2013), online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90550/554112/666941/737909/914331/914110/A3F0Y9_-_National_Energy_Board_Report_for_Proceeding_GH-001-2012.pdf?nodeid=913955&vernum=0> [*NOVA Gas*].

2 *Jobs, Growth and Long-term Prosperity Act*, SC 2012, c 19; *National Energy Board Act*, RSC 1985, c N-7 [*NEB Act*].

3 *NOVA Gas*, *supra* note 1 at iv.

4 *Ibid* at 4.

5 *Ibid* at 2.

However, with respect to the Komie North Section and the need for facilities, the NEB determined that the likelihood of the Komie North Section being utilized at a reasonable level depended on the appropriateness of the proposed toll treatment.[6] The NEB found that the proposed toll treatment for the Komie North Section was inappropriate because it would unreasonably subsidize the extension of the NOVA Alberta System into an area where it would compete with existing infrastructure.[7] The NEB further provided that basing pricing for transportation on cost causation promotes economic efficiency through proper price signals to the market. The NEB was of the view that the tolls for NOVA's transmission service must adequately allocate costs and risks, and the NEB did not restrict the revised toll treatment that NOVA may develop for the Komie North Section. The NEB concluded that the need for the facilities was considered uncertain.[8]

The NEB further found the economic feasibility of the Project in the Komie North Section unacceptable because the throughput forecast provided by NOVA did not represent a solid basis for the NEB to conclude the Komie facilities would be used and useful over their economic life. There were also concerns with shipper support and the recovery of costs.[9]

The NEB concluded that the commercial impacts to others were unacceptable because the Project would entice volumes away from Westcoast's system by offering an alternative path to markets priced well below cost. This would negatively affect Westcoast's transmission, gathering, and processing facilities, as well as Westcoast's shippers.[10] The NEB concluded that approval of the Komie North Section was not in the public interest.[11]

The NEB stated that should the Governor in Council direct the NEB to issue a Certificate with respect to the Komie North Section, Condition 17 set out in the Decision had to be satisfied, along with other conditions. Condition 17 included pre-construction, construction, and post-construction elements. Some items that had to be satisfied in Condition 17 included, among other things, implementation of environmental protection policies, filing with the NEB for approval of an Environmental Protection Plan prior to commencing construction, various habitat plans and assessments to be filed prior to commencement of construction, and aboriginal consultation reports to be filed prior to construction.[12] The Governor in Council agreed with the NEB's recommendations, directing the NEB to issue NOVA a Certificate for the Chinchaga section of the Northwest Mainline Komie North Extension Project only, subject to the conditions outlined in the NEB's report.[13]

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6 *Ibid* at 16.
7 *Ibid* at 30.
8 *Ibid* at 30-31.
9 *Ibid* at 42.
10 *Ibid* at 45.
11 *Ibid*.
12 *Ibid* at 2; Appendix IV at 97-107.
13 *Orders in Council* National Energy Board, PC 2013-379, (2013) C Gaz 1, 875.

2. ENBRIDGE PIPELINES INC. — LINE 9 REVERSAL PHASE ONE PROJECT[14]

Enbridge Pipeline Inc.'s (Enbridge) application dealt with a proposal to reverse the flow of a major inter-provincial pipeline. The decision is instructive for future applications for similar flow reversals.

a. Application

On 8 August 2011, Enbridge applied pursuant to section 58 of the *NEB Act* to reverse the flow of the 194 kilometer long segment of Line 9 between the Sarnia Terminal and the North Westover Pump Station (the Application). Enbridge also requested exemption from Leave to Open (LTO) under section 47 of the *NEB Act*. Enbridge proposed infrastructure additions and modifications at four existing fenced and graveled sites to allow this reversal.[15]

b. Background

The Enbridge Line 9 is an approximately 830 kilometer long, 30-inch outside diameter crude oil pipeline between Sarnia, Ontario and Montreal, Quebec. Line 9 was placed into service in 1976 with an eastward flow. The flow of the pipeline was reversed to a westward direction in 1999.[16]

c. Key Findings and Decision

The NEB considered the need for the Project and potential commercial impacts, Enbridge's public consultation, Aboriginal engagement, environment and socio-economics, pipeline abandonment, and engineering and integrity. The NEB concluded that it would be in the public interest to approve the Project.[17]

The Project was approved subject to certain conditions. The conditions included: Enbridge's implementation of environmental protection and mitigation measures, procedures, and recommendations; the filing of an emergency plan with the NEB prior to construction; the filing of a construction schedule and a Commitments Tracking Table with the NEB; the filing of construction progress reports to the NEB on a monthly basis; running in-line inspections 18 months following the receipt of NEB approval for LTO; the filing of a proposed long-term integrity improvement plan to mitigate and monitor corrosion, geometry, and cracking features in the pipeline sections between Sarnia and Westover;[18] and that Enbridge apply for LTO prior to commencing reversed flow operation.

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14 *Enbridge Pipelines Inc Line 9 Reversal Phase I Project*, OH-005-2011, Letter from RR George, GA Habib & L Mercier to Chantal Robert & Francis P Dunford (27 July 2012), online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/92263/706191/706437/834328/834582/A2V3K2_-_Letter_Decision_OH-005-2011.pdf?nodeid=834303&vernum=0>.

15 *Ibid* at 1.

16 *Ibid*.

17 *Ibid* at 28.

18 *Order XO-E101-010-2012*, (27 July 2012), online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/92263/706191/706437/834328/834582/A2V3K6_-_Appendix_II_Order_XO-E101-010-2012.pdf?nodeid=834586&vernum=0>.

3. LNG CANADA DEVELOPMENT INC. — LICENCE TO EXPORT LIQUIFIED NATURAL GAS[19]

LNG Canada Development Inc.'s (LNG Canada) application involved a significant natural gas liquefaction export terminal and storage facility to be constructed in Kitimat, British Columbia.

a. Application

On 27 July 2012, LNG Canada applied to the NEB pursuant to section 117 of the *NEB Act* (the Application) for a licence authorizing the export of liquefied natural gas (LNG). LNG Canada sought a licence term of 25 years, starting on the date of first export, and a maximum annual volume of 24 million tonnes of LNG. LNG Canada further requested a 15 percent annual tolerance to accommodate operating variables. LNG Canada proposed that the point of export be at the outlet of the loading arm of a proposed natural gas liquefaction terminal to be located near Kitimat, British Columbia.

b. Background

The Terminal is being developed under a Joint Development Agreement among Shell Canada Limited, Diamond LNG Canada Ltd., Kogas Canada LNG Ltd. and Phoenix Energy Holdings Limited.

c. Key Findings and Decision

The NEB noted that it was bound by the powers granted to it by legislation, namely section 118 of the *NEB Act*, which provided that:

> On an application for licence to export oil or gas, the Board shall satisfy itself that the quantity of oil or gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada.[20]

The NEB concluded that it may only consider the "surplus" criterion in section 118 and cannot consider unrelated matters and accordingly "surplus" was the focus of its assessment of the Application.[21]

The NEB found that "surplus" must be considered in light of the dynamic marketplace for natural gas in North America and the needs of Canadians. The NEB was satisfied that the gas

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19 *LNG Canada Development Inc Application for a Licence to Export Liquefied Natural Gas pursuant to Section 117 of the National Energy Board Act, OF-EI-Gas-GL-L384-2012-01 01*, Letter from G Caron, L Mercier & D Hamilton to Lars Olthafer & Scot MacKillop (4 February 2013), online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90466/94153/552726/834773/834774/915307/A3F2D6_-_LNG_Canada_Development_Inc._Application_for_a_Licence_to_Export_Liquefied_Natural_Gas_-_National_Energy_Board_Reasons_for_Decision?nodeid=915693&vernum=0> [LNG Letter Decision].

20 *Supra* note 2. See also LNG Letter Decision, *ibid* at 3.

21 LNG Letter Decision, *ibid*.

resource base in Canada (and North America) is large and can easily accommodate reasonably foreseeable Canadian demand as well as the proposed LNG exports. The NEB also found that the incremental cost of adding new production to displace any exported LNG is low and that the North American gas market is sufficiently large and integrated, such that market participants have a multitude of options for securing gas supplies. The NEB noted that there was no evidence to suggest that North American gas markets would not continue to function efficiently in the future. Based on the foregoing, the NEB was satisfied that the quantity of gas to be exported did not exceed the surplus remaining after due allowance had been made for the reasonably foreseeable requirements for use in Canada.[22]

With respect to concerns raised by Fort Nelson First Nation, Gitga'at First Nation, and Gitxaala Nation, the NEB found these concerns related to the potential adverse impacts of physical activities (such as the Terminal and associated facilities). The NEB was satisfied that the issuance of a licence would not directly or indirectly authorize or cause the activities and associated potential adverse impacts that were of concern to the aboriginal groups. Moreover, the issuance of the licence would not impact the ability for meaningful consultation to take place during the course of those other decision-making processes.[23]

With respect to the applicability of the *Canadian Environmental Assessment Act, 2012*[24] the NEB decided that the Application did not trigger the environmental assessment requirements under that legislation. The test under section 7 of *CEAA 2012* was whether the licence "would permit a designated Project to be carried out in whole or in part," not whether a designated Project would be carried out without the export licence.[25] The NEB concluded that its decision on this Application would not permit the Terminal and any associated facilities or physical activities to be carried out. Therefore an environmental assessment would not be required.[26]

The NEB issued a licence to export liquefied natural gas, subject to certain terms and conditions and the approval of the Governor in Council. The term of the licence will commence on the date of first export from the liquefaction terminal near Kitimat, British Columbia, and will continue for 25 years thereafter.[27] The Governor in Council has approved the decision, although a judicial review of this decision has been commenced in the Federal Court.[28]

22 *Ibid* at 4.
23 *Ibid* at 6.
24 SC 2012, c 19 [*CEAA 2012*].
25 LNG Letter Decision, *supra* note 19 at 7.
26 *Ibid*.
27 *Ibid* at 11-12.
28 PC 2012-0408 (5 April 2013); see *Gitxaala Nation v Governor in Council*, Ct No T-520-13.

4. TRANSCANADA PIPELINES LIMITED, NOVA GAS TRANSMISSION LTD., AND FOOTHILLS PIPE LINES LTD.[29]

The TransCanada Mainline pipeline system is one of the most important components of Canada's energy infrastructure. Accordingly, the tolls charged are of significance to producers, shippers, and, ultimately, consumers throughout the country.

a. Application

On 1 September 2011, TransCanada PipeLines Limited (TransCanada), NOVA, and Foothills Pipe Lines Ltd. (Foothills) applied to the NEB under Parts I and IV of the *NEB Act* for approvals required to implement a proposed restructuring of the services on the TransCanada Mainline pipeline system (Mainline), the TransCanada Alberta System (the Alberta System) and the TransCanada Foothills System (the Foothills System). "TransCanada also applied for orders fixing and approving tolls that it shall charge for transportation services provided on the Mainline between 1 January 2012 and 31 December 2013."[30]

b. Background

TransCanada owns and operates the Mainline (a high-pressure natural gas transmission system) that extends from Empress, Alberta across Saskatchewan, Manitoba, Ontario, through a portion of Quebec, and connects to various downstream Canadian and international pipelines. There are three segments: (1) the Prairies segment (from Empress, Alberta to a point near Winnipeg, Manitoba); (2) the Northern Ontario Line (which runs from Winnipeg to a point near North Bay, Ontario); and (3) the Eastern Triangle (which runs from North Bay to a point near Toronto and eastward to a point near Ottawa, Ontario). The Mainline integrated system can transport up to 7.0 billion cubic feet per day of Western Canada Sedimentary Basin (WCSB) gas.[31]

NOVA owns the Alberta System, a natural gas transmission system in Alberta and northeast British Columbia, while "Foothills is a wholly-owned subsidiary of TransCanada and is a large diameter natural gas pipeline system extending from central Alberta to points at the Canada/U.S. border near Kingsgate, B.C. and near Monchy, Saskatchewan to serve markets in the US Midwest, Pacific Northwest, California and Nevada."[32]

No major NEB regulated natural gas transmission pipeline had ever been affected by market forces to the extent that the Mainline was affected; as a result, the Mainline was in an unprecedented position.[33] Mainline tolls had increased substantially over a short period

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29 *Reasons for Decision: TransCanada PipeLines Limited, NOVA Gas Transmission Ltd, and Foothills Pipe Lines Ltd*, RH-003-2011 (March 2013), online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92833/92843/665035/711778/941262/939799/A3G4A3_-_TransCanada_PipeLines_Limited,_NOVA_Gas_Transmission_Ltd._and_Foothills_Pipe_Lines_Ltd._Hearing_Order_RH-003-2011_Reasons_for_Decision?nodeid=939800&vernum=0>.
30 *Ibid* at 5.
31 *Ibid* at 5-6.
32 *Ibid* at 6.
33 *Ibid* at 1.

of time due to decreased throughput on the Mainline. The Mainline faced increasing competition for gas supply from intra-Alberta demand, other ex-WCSB pipelines, and new markets for WCSB gas. The Mainline also faced competition with pipelines from shale and tight gas basins in the US. The NEB provided that the Mainline must adjust to this new environment because eastern customers may not renew contracts for long-haul service and bypass infrastructure may be built.[34]

The NEB issued this decision stating that the "[t]olls cannot continue to increase each year in response to throughput decline."[35]

c. Key Findings and Decision

The NEB approved a multi-year fixed tolls approach to stop the toll increases. The NEB provided that given the increase in throughput that is forecasted, averaging the Firm Transportation (FT) toll over a multi-year period lowers the toll immediately and better allows the Mainline to compete. This approach provides "toll certainty and stability for shippers" (who noted that it was difficult to make contracting and investment decisions without knowing how much it would cost to transport on the Mainline).[36]

The NEB set the FT toll from Empress, Alberta to Dawn, Ontario at $1.42/gigajoule (GJ), compared to a 2013 toll of $2.58/GJ that would result from TransCanada's existing toll methodology. This new toll is to remain in effect through 2017.[37] The NEB, in recognition of the business risk that the Mainline was facing, approved the Mainline's return on equity at 11.5 percent on a 40 percent equity ratio.[38] The NEB "also approved an incentive mechanism that would further increase the Mainline's profits if annual net revenues are higher than forecasted."[39]

The NEB approved several elements of TransCanada's Restructuring Proposal, included all of TransCanada's proposed changes to the Mainline's cost allocation, and the elimination of toll zones and the elimination of the Risk Alleviation Mechanism. The NEB conferred greater discretion on TransCanada than it proposed in how it prices Interruptible Transportation (IT) service and Short Term Firm Transportation (STFT) service.[40]

The NEB did not approve the Alberta System Extension, the reallocation of accumulated depreciation, and the proposed treatment of, costs related to TransCanada's agreement for transportation services on TransQuebec and Maritimes Pipeline Inc.'s pipeline system. The Alberta System Extension was viewed by the NEB as inappropriate cost shifting among affiliate companies contrary to sound tolling principles.[41] The Alberta System Extension violated the principle that shippers' costs and benefits do not extend beyond a contract under

34 *Ibid* at 1.
35 *Ibid*.
36 *Ibid* at 2.
37 *Ibid* at 1.
38 *Ibid*.
39 *Ibid*.
40 *Ibid*.
41 *Ibid* at 2.

which services were requested and made available. Therefore, the NEB held that the Alberta System Extension "cannot produce tolls that are just and reasonable."[42]

The NEB concluded that the pricing methodology for IT and STFT was not appropriate and that shippers using IT or STFT to meet a firm operating requirement do not contribute sufficiently to the Mainline's fixed costs. The NEB afforded TransCanada greater discretion than they provided in their Restructuring Proposal to set price floors to give TransCanada the opportunity to recover the costs of its capacity. The NEB made TransCanada accountable for how it exercises this discretion and encouraged TransCanada to make decisions that result in the greatest net revenue for the Mainline, benefitting shippers who require the service.[43]

The NEB also developed and will implement a streamlined regulatory process for new service and pricing proposals on the Mainline. This will allow the Mainline to address new service and pricing proposals in a more timely manner.[44]

Finally, the NEB did not disallow any Mainline investment from being recovered in tolls. Based on the forecast increase in Mainline throughput, the NEB found that TransCanada should be afforded the time and tools to adapt to the business environment. Because the Mainline will face increased variability risk due to its cash flows being more dependent on the accuracy of its throughput forecast, the NEB compensated it through a higher allowed return.[45]

In summary, the NEB issued a decision to enable TransCanada to meet market forces with a market solution. The NEB provided the Mainline with tools to respond to increasing competitive risk coupled with regulatory process flexibility to effect the appropriate changes. The NEB concluded that it is TransCanada's responsibility to ensure that the Mainline is economically viable and continues to be an important asset to connect the WCSB to markets in the east. Further, the extent to which the Mainline is used by producers and consumers can only be determined by a functioning free market. The NEB instructs TransCanada to not look to regulation to shield the Mainline from its fundamental business risk; "it must address the underlying competitive reality in which [it] operates."[46]

B. CANADIAN ENVIRONMENTAL ASSESSMENT AGENCY

1. CENOVUS ENERGY — SHALLOW GAS INFILL DEVELOPMENT PROJECT[47]

This is the first significant consideration of a Project under the new *CEAA 2012* regime.

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42 *Ibid*.
43 *Ibid*.
44 *Ibid* at 3.
45 *Ibid*.
46 *Ibid*.
47 *Decision Statement, EnCana Shallow Gas Infill Development Project in the Suffield National Wildlife Area*, Doc No 891 (30 November 2012), online: CEAA <http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=83796>.

a. Application

Cenovus Energy proposed to develop up to 1,275 shallow gas wells and associated infrastructure over a three year period within the Canadian Forces Base Suffield National Wildlife Area (the Area) in southern Alberta.[48]

b. Background

The Project is an "infill" development that would more than double the number of existing wells in the Area. The Area was created in recognition of its ecological integrity and the diversity and abundance of native plant and animal species. It is one of the few large blocks of dry mixed-grass prairie remaining in Canada and accounts for approximately 30 percent of all the protected grasslands in Alberta. The Area encompasses a large area of prairie grassland and is home to over 1,100 catalogued species including 19 terrestrial species listed under the *Species at Risk Act*.[49]

An environmental assessment of the Project was commenced under the former *Canadian Environmental Assessment Act* and was referred to a review panel by the Minister of the Environment under that *Act*.[50] The Minister, along with the then Alberta Energy and Utilities Board agreed to a joint review panel to review the environmental effects of the Project.[51]

The *CEAA 2012* came into force on 6 July 2012. The assessment by the review panel established under the former *Act* was continued under the process established under *CEAA 2012*. The Project was considered to be a "designated project" for the purposes of *CEAA 2012*.[52]

c. Key Findings and Decision

After taking the review panel's report into account, the Minister decided that the Project was not likely to cause significant adverse environmental effects referred to in section 5(2) of *CEAA 2012*.[53]

The Minister referred the determination of whether the significant adverse environmental effects referred to in section 5(1) are justified in the circumstances to the Governor in Council.[54]

The Governor in Council decided that the significant environmental effects likely caused by the Project were not justified in the circumstances and that Cenovus must not do any act

48 *Ibid*.
49 SC 2002, c 29; *News Release: Due to Potential Significant Environmental Impacts, Federal Approval not Granted for Project*, Doc No 892 (30 November 2013), online: CEAA <http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=83803> [*News Release*].
50 SC 1992, c 37.
51 *News Release, supra* note 49.
52 *Ibid*.
53 *Ibid*.
54 *Ibid*.

or thing in connection with carrying out the Project (in whole or in part) if that act may cause an environmental effect referred to in section 5(1) of *CEAA 2012*.[55]

C. ENERGY RESOURCES CONSERVATION BOARD

This Application is for the most advanced carbon capture and storage facility in Alberta.

1. SHELL CANADA — APPLICATION FOR THE QUEST CARBON CAPTURE AND STORAGE PROJECT[56]

a. Application

Shell Canada (Shell) applied, pursuant to the *Pipeline Act*,[57] "for a pipeline to transport dense-phase carbon dioxide (CO_2)"[58] and the *Oil and Gas Conservation Act*[59] for an approval to dispose of carbon dioxide (a Class III fluid) into the Basal Cambrian Sands (BCS) in and around the Radway Field. Shell also applied to convert its test well into a Class III injection well in order to inject CO_2 into the BCS.[60] Lastly, Shell applied pursuant to the *Oil Sands Conservation Act*, to amend its existing approval to construct and operate facilities for the capture of CO_2 at its Scotford Upgrader.[61]

b. Background

The Quest Carbon Capture and Storage Project (the Project) involves the capture of CO_2 at the Scotford Upgrader north of Edmonton, Alberta, the subsequent transportation of CO_2 by pipeline to the Radway Field, and the injection of CO_2 into the BCS for sequestration.[62]

c. Key Findings and Decision

The ERCB determined that it was in the public interest to proceed with the Project, noting the proposed reservoir is a suitable location for the long-term storage of carbon dioxide and that the combination of geological conditions, engineering design, operational practices, and an extensive monitoring program mitigate any potential risks the Project might pose.[63]

The Energy Resources Conservation Board (ERCB) noted that "one of the purposes of the *OGCA* is to ensure safe and efficient practices in operations involving the storage or disposal of substances."[64] The ERCB accepted Shell's submission that its Quest CO_2 sequestration

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55 *Ibid.*
56 *Shell Canada Limited: Application for the Quest Carbon Capture and Storage Project Radway Field*, 2012 ABERCB 008 (10 July 2012), online: ERCB <http://www.aer.ca/documents/decisions/2012/2012-ABERCB-008.pdf> [*Shell*].
57 RSA 2000, c P-15.
58 *Shell*, *supra* note 56 at para 2.
59 RSA 2000, c O-6 [*OGCA*].
60 *Shell*, *supra* note 56 at para 3.
61 RSA 2000, c O-7; *Shell*, *ibid* at para 4.
62 *Shell*, *ibid* at paras 5-9.
63 *Ibid* at paras 390-409.
64 *Ibid* at para 65.

scheme is needed in order for Shell to meet its corporate greenhouse gas reduction targets and to fulfill its commitments to the provincial and federal governments.[65]

The ERCB concluded that "the capture, transportation, injection, and sequestration of the CO_2 [would] not interfere with the recovery or conservation of oil or gas."[66] Further, the Project would not interfere with the storage of oil or gas within the sequestration area of interest.[67] As a result, the ERCB approved the applications.

The ERCB applied 23 conditions on its approval of the Project, primarily regarding additional data collection, analysis, and reporting. Shell must also obtain separate approvals for any additions to the Project.[68]

D. ALBERTA UTILITIES COMMISSION

1. RATE REGULATION INITIATIVE — DISTRIBUTION PERFORMANCE-BASED REGULATION[69]

This proceeding is an important advancement of the Alberta Utilities Commission's (AUC) implementation of performance-based rate making (PBR), specifically as it is applied to the rate-making for electric and gas distribution companies.

a. Application

On 26 February 2010, the AUC initiated a review of PBR in an effort to reform utility rate regulation in Alberta.[70]

b. Background

This decision applies to three electric distribution companies (ATCO Electric Ltd., FortisAlberta Inc., and EPCOR Distribution & Transmission Inc.) and two gas distribution companies (ATCO Gas and Pipelines Ltd. and AltaGas Utilities Inc.). Prior to this Decision, the distribution and transmission services charged by these companies were derived under a rate base, rate-of-return form of cost of service regulation.[71]

Under that system, utility rates were set by adding up the expenses of a utility in providing utility service, plus a pre-determined rate of return for the utility company. Those overall costs were then paid by ratepayers. When a utility's expenses rose, its rates rose. This created stronger incentives to choose spending money on capital assets, on which a return can be earned, over spending on maintenance (for example) where a return is not earned.[72] There

65 *Ibid* at para 67.
66 *Ibid* at para 416.
67 *Ibid*.
68 *Ibid* at Appendix 2.
69 *Rate Regulation Initiative: Distribution Performance-Based Regulation*, Decision 2012-237 (12 September 2012), online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>.
70 *Ibid* at para 1.
71 *Ibid* at para 5.
72 *Ibid* at para 11.

was also no incentive to minimize the costs of capital assets: "The more that was spent and included in the company's rate base, the more return that could be earned."[73]

This resulted in the AUC making an after-the-fact assessment of whether the company spent too much money on capital assets and, if required, disallow recovery of the amount by which actual costs exceeded the appropriate amount.[74]

As noted by the AUC, rate-base rate of return regulation is increasingly cumbersome in an environment where some companies offer both regulated and unregulated services and where operations that were formerly integrated have been separated into separate operating companies, some of which require their own rate and revenue proceedings.[75]

c. Key Findings and Decision

The AUC implemented PBR for electric and natural gas distribution companies in place of the existing cost of service regulatory system.

PBR is a method of calculating and setting utility rates using a formula that adjusts utility rate changes to inflation minus an enhanced efficiency or industry productivity factor (X factor). The AUC determined that, except in limited circumstances, rates can only rise at a rate that is lower than that of inflation. Prices adjusted by this formula reflect industry-wide conditions that would produce industry price changes in a competitive market. Each company's performance will depend on how its own performance compares to the industry's inflation and productivity measures.[76]

PBR is designed to provide incentives for companies to operate more efficiently through cost reductions and other actions because they are able to keep their increased profits generated by these cost reductions longer than they would under the cost of service regulation; "customers automatically share in the expected efficiency gains because they are built into the rates through the X factor regardless of actual performance of the companies."[77]

The initial PBR will be in place for a five-year term at which time the plan will be evaluated with respect to how it might be re-initiated at the end of that term.[78]

A number of the affected companies subsequently sought review and variance of this Decision. These applications were dismissed by the AUC.[79]

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73 *Ibid*.
74 *Ibid*.
75 *Ibid* at para 14.
76 *Ibid* at para 16.
77 *Ibid* at para 17.
78 *Ibid* at para 839.
79 *Rate Regulation Initiative: Distribution Performance-Based Regulation Decision on Preliminary Question Requests for Review and Variance of AUC Decision 2012-237*, Decision 2013-071 (4 March 2013), online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2013/2013-071.pdf>.

2. HEARTLAND TRANSMISSION PROJECT — DECISION OF REQUEST FOR REVIEW AND VARIANCE

This Decision[80] is significant as it was the first review and variance of a major Critical Transmission Infrastructure (CTI) Project.

a. Application

Six parties asked the Commission to review and vary Decision 2011-436 (the Heartland Decision).[81] Some parties focused on the decision to reject the underground option for the transmission line, others focused on the approval of the route near their respective lands.[82]

b. Background

The introduction of this decision provides useful background information:

> On 26 September 2010, AltaLink Management Ltd. and EPCOR Transmission and Distribution Inc. (the Heartland Applicants) filed an application to construct and operate a double-circuit 500 kilovolt transmission line to connect the existing 500 kilovolt system on the south side of Edmonton to a new substation to be located in the Gibbons-Redwater area. The Heartland application included a preferred route and an alternate route. The Heartland application also included an option in which the first 20 kilometres of the preferred route would be installed underground.[83]

The AUC approved the preferred route on 1 November 2011, but rejected the underground option because "the health and safety, property value and environmental impacts individually or together do not justify the additional cost of placing the line underground."[84]

c. Key Findings and Decision

The AUC decided that while certain individuals were not registered participants in the Heartland proceeding, they were directly and adversely affected by the Heartland Decision and had standing to bring a review application.[85]

The AUC concluded on various issues that none of the review applicants raised a substantial doubt as to the correctness of the Heartland Decision, according to the criteria set out in AUC Rule 016 and decisions of the Alberta Court of Appeal, due to an error of fact, law, or jurisdiction. The AUC did not find support for contentions that the hearing panel failed to consider evidence (or that evidence being presented to the review panel had not been previously considered by the hearing panel),[86] concluded that the hearing panel was

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80 *AltaLink Management Ltd and EPCOR Distribution & Transmission Inc: Decision on Request for Review and Variance of AUC Decision 2011-436*, Decision 2012-124 (14 May 2012), online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-124.pdf>.
81 *Ibid* at para 3.
82 *Ibid* at para 5.
83 *Ibid* at para 1.
84 *Ibid* at para 2.
85 *Ibid* at para 34.
86 *Ibid* at paras 46, 126, 136.

reasonable in coming to its conclusions,[87] and found that the hearing panel had not committed an error of fact or law that could create a reasonable possibility that the AUC could materially vary or rescind the Heartland Decision.[88]

3. MARKET SURVEILLANCE ADMINISTRATOR — APPLICATION FOR APPROVAL OF A SETTLEMENT AGREEMENT[89]

Here, the AUC levied substantial administrative penalties against a market participant, above what was agreed to by the Market Surveillance Administrator (MSA).

a. Application

The application was made as follows:

> On 4 November 2011, the [MSA] filed an application with [the AUC], pursuant to sections 44 and 51 of the *Alberta Utilities Commission Act* [the *AUC Act*] … requesting that the AUC consider and approve the terms of a settlement agreement dated 4 November 2011 (settlement agreement), between the MSA and TransAlta Energy Marketing Corp. (TransAlta).[90]

b. Background

The application and Settlement Agreement related to intertie scheduling activities of TransAlta that had the effect of impeding import transactions which otherwise would have occurred. The MSA viewed this as a breach of section 6 of the *Electric Utilities Act* through contravention of section 2(h) of the *Fair, Efficient and Open Competitoin Regulation* (conduct that does not support the fair, efficient, and openly competitive operation of the market).[91]

c. Key Findings and Decision

The AUC approved of the Settlement Agreement with reservations.

The AUC considered that the resulting harm was a significant factor and that TransAlta contravened the legislation as a result of direct and deliberate actions on their part, knowing of the impact of their actions on the pool price for electricity and on other parties across the province. TransAlta did not self-report these actions to the MSA. As a result, the AUC applied an administrative penalty of $125,000 in addition to the disgorgement of $245,073.34 (the economic benefit derived by TransAlta as a result of its actions).[92]

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87 *Ibid* at paras 52, 125.

88 *Ibid* at paras 70, 73, 82, 101, 160.

89 *Market Surveillance Administrator: Application for Approval of a Settlement Agreement between the Market Surveillance Administrator and TransAlta Energy Marketing Corp*, Decision 2012-182 (3 July 2012), online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-182.pdf> [*Market*].

90 *Ibid* at para 2; *Alberta Utilities Commission Act*, SA 2007, c A-37.2 [*AUC Act*].

91 *Electric Utilities* Act, RSA 2003, c E-5.1 [*EUA*]; *Fair, Efficient and Open Competition Regulation*, Alta Reg 159/2009; *Market*, *ibid* at para 3.

92 *Market*, *ibid* at paras 74-75.

The AUC also differentiated between specific penalties and administrative penalties. In doing so, the AUC rejected the MSA's submission that AUC Rule 019 (which deals with specified penalties for contravention of ISO rules) and AUC Rule 027 (dealing with specified penalties for contravention of Alberta reliability standards) were relevant and instructive. First, the AUC had not determined that all ISO rules and reliability standards were eligible for specific penalties pursuant to section 52(7) of the *AUC Act*. Second, the specified penalty tables did not take into account specific market impact and impact to others; the administrative penalty adds a one-time amount to address an economic benefit derived directly or indirectly as a result of contravention.[93] Finally, there was no legislation making specified penalties applicable for contravention of legislation or regulation.[94]

Because the circumstances of this case were neither typical nor routine, the AUC determined that the specified penalties put forward by MSA did not apply.[95] The application for approval of the settlement agreement was granted and TransAlta was ordered to pay an administrative penalty of $370,073.34 to the AUC.[96]

4. ATCO ELECTRIC LTD. — EASTERN ALBERTA TRANSMISSION PROJECT[97]

Along with the Western Alberta Transmission Project and the Heartland Project, approved in 2011, this is one of four CTI Projects.

a. Application

ATCO Electric Ltd. (ATCO) "filed an application with the AUC to construct and operate a 500 kilivolt (kV) direct-current transmission line" between the Gibbons area, northeast of Edmonton, and the Brooks area, southeast of Calgary.[98]

The application also proposed to construct and operate a converter station at each end of the line, and to construct and operate related facilities to convert power from alternating-current to direct-current and to connect the new facilities to the Alberta Interconnected Electric System.[99]

b. Background

CTI Projects are unique in that the need for each Project was determined by the legislation leaving the AUC to only consider the best route alternative for each Project.

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93 *Ibid* at para 77.
94 *Ibid*.
95 *Ibid* at para 78.
96 *Ibid* at para 79.
97 *ATCO Electric Ltd: Eastern Alberta Transmission Line Project*, Decision 2012-303 (15 November 2012), online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-303.pdf>.
98 *Ibid* at para 1.
99 *Ibid*.

c. Key Findings and Decision

The AUC approved portions of the ATCO's preferred route and, in several cases, portions of the alternative route submitted by ATCO. Overall, based on land-use, cost, and environmental considerations, the route selected by the AUC was found to be both in the public interest and superior to other potential routes.[100]

5. ALTALINK MANAGEMENT LTD. — WESTERN ALBERTA TRANSMISSION LINE PROJECT[101]

Along with the Eastern Alberta Transmission Project and the Heartland Project, approved in 2011, this is one of four CTI Projects.

a. Application

On 1 March 2011, AltaLink Management Ltd. (AltaLink) filed an application with the AUC for approval to construct and operate a 500 kV, direct-current transmission line with associated converter stations and equipment that would extend approximately 350 kilometers from Genesee, west of Edmonton, to the Langdon area east of Calgary.[102]

b. Background

As with all CTI projects, the need for the line was specified by the Alberta government as CTI in 2009 in the *Electric Statutes Amendment Act, 2009*.[103]

In its application, Altalink "identified both a preferred route, primarily selected for paralleling existing transmission lines and an alternate route primarily across greenfield areas" (where there were no transmission lines) and, "[o]n each route, some route options were proposed." AltaLink did not propose an underground option on any part because the undergrounding of direct current transmission lines had not been technically or commercially proven and "would significantly increase the cost of the proposed transmission line."[104]

c. Key Findings and Decision

The AUC approved AltaLink's preferred route along with a short alternate route proposed by AltaLink and the facilities associated with the Project.[105]

Two interveners raised a constitutional argument challenging whether the AUC had jurisdiction to consider the Project. They argued that the Project is an inter-provincial or

100 *Ibid* at para 981.
101 *AltaLink Management Ltd: Western Alberta Transmission Line Project*, Decision 2012-327 (6 December 2012), online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-327.pdf> [*AltaLink Western*].
102 *Ibid* at para 2.
103 Bill 50, *Electric Statutes Amendment Act, 2009*, 2nd Sess, 27th Leg, Alberta (2009) (assented to 26 November 2009) [*ESAA*].
104 *AltaLink Western*, *supra* note 101 at para 14.
105 *Ibid* at para 1140.

international undertaking by virtue of its proximity to the British Columbia Intertie and therefore is under the jurisdiction of the NEB. The AUC found that the Project will have its start and end points within Alberta and that it will be a part of the Alberta Interconnected Electric System. Therefore, it is a local work that falls under provincial jurisdiction.[106]

E. ALBERTA SURFACE RIGHTS BOARD

1. Williams Energy (Canada) Inc. — Right of Entry Order[107]

A long-standing approach to determining compensation by the Alberta Surface Rights Board (SRB) is reviewing payment levels set by voluntary negotiation between landowners and operators. If the number of agreements is sufficient to show a pattern of dealings exists in a certain area, the SRB can follow the pattern and set compensation accordingly.[108]

Generally, the SRB's consideration of a pattern of dealings captures initial consideration within the pattern. Here, however, the SRB deviated from this prevailing approach.

a. Application

This decision determined the amount of compensation payable to the Respondent landowner.

b. Background

A Right of Entry Order was issued to the Operator, Williams Energy (Williams), with respect to a pipeline near the town of Redwater. This decision concerned compensation for this pipeline.

c. Key Findings and Decision

The SRB determined that a pattern of dealings existed in this matter of $8,000 per acre because Williams presented seven negotiated agreements, all signed at $8,000 per acre, between Williams and landowners on the subject pipeline, and all the intermunicipal fringe (immediately outside the boundaries of the town). The SRB found that there was no cogent reason to depart from this pattern.[109] Due to this finding of fact, the SRB determined that it was not bound by an Alberta Queen's Bench decision coming to a different conclusion as to whether initial consideration should be considered part of the pattern of dealings. The SRB considered the evidence and concluded that under these negotiated agreements, the landowners granted a right-of-way in exchange for an initial payment of $150 per acre and an additional payment of $8,000 per acre.[110] This determination included compensation for loss of future development potential.[111]

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106 *Ibid* at para 429.
107 *Williams Energy (Canada), Inc v 1265536 Alberta Ltd*, 2012 ABSRB 849 (CanLII).
108 *Ibid* at 10-11.
109 *Ibid* at 4.
110 *Ibid* at 5.
111 *Ibid* at 7.

F. ONTARIO ENERGY BOARD

1. UNION GAS LIMITED

a. Application

On 10 November 2011, Union Gas Limited (Union)[112] filed an application with the Ontario Energy Board (OEB) "under section 36 of the *Ontario Energy Board Act, 1998* for an order of the [OEB] approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2013."[113]

b. Background

The OEB noted that "[t]his was the first cost-of service application for setting rates since 2007. From 2008-2012 rates were set under an Incentive Regulation Mechanism (IRM) which adjusted rates through a mechanistic formula."[114]

Union originally filed its Application on the basis of US Generally Accepted Accounting Principles (GAPP). At the same time, Union sought approval to move from Canadian GAAP to US GAAP as part of this Application.[115] At a Settlement Conference several issues were settled between Union and the interveners, which included shippers and an industry association. They reached an agreement with respect to rate base and cost of service for the test year, along with several other issues outlined in a Settlement Agreement.[116]

c. Key Findings and Decision

The key finding of this decision related to optimization and the gas supply plan. The gas supply plan was intended to ensure that customers receive secure, diverse gas supply at a prudently incurred cost.[117] The OEB explained that it did not agree with Union's arguments that the optimization activities were sustainable efficiency improvements found by Union in 2011 and 2012. Instead, the OEB held that the optimization revenues were clearly related to reductions in upstream transportation costs that resulted in an overall reduction to Union's supply chain costs. As such, given that these cost reductions are subject to "pass through" treatment, the OEB held that they must accrue to customers.[118]

The OEB cited the long-standing principle that a gas utility should not profit from the procurement of gas supply for its in-franchise customers. In order to eliminate the creation of inappropriate incentives during the test year, the OEB found that the optimization activities are to be considered part of gas supply (upstream gas costs and cost of

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112 *Union Gas Limited: Application for Approval or Fixing of Just and Reasonable Rates*, EB-2011-0210 (25 October 2012) [*Union*].
113 SO 1998, c 15; *Union, ibid* at 1.
114 *Union, ibid*.
115 *Ibid* at 2.
116 *Ibid* at 5.
117 *Ibid* at 32.
118 *Ibid* at 39.

transportation required to deliver gas supply to Union's in-franchise customers), not part of transactional services.[119]

The OEB defined optimization as "any market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise bundled customers."[120]

The OEB determined that the revenues realized by Union from the optimization of upstream transportation contracts must be reclassified as gas supply costs. As a result, approximately 90 percent of the total reclassified revenues equaling approximately $30 million will be refunded to customers, while the remaining 10 percent shall accrue to Union as an incentive to continue to undertake optimization activities on behalf of rate payers following implementation of the order and rate changes in January 2013.[121]

G. ONTARIO ENVIRONMENTAL REVIEW TRIBUNAL

1. *HALDIMAND WIND CONCERNS V. DIRECTOR, MINISTRY OF THE ENVIRONMENT*[122]

This appeal constitutes one of the first significant challenges to a wind power project in Ontario.

a. Application

On 31 July 2012, Haldimand Wind Concerns (HWC) filed appeals and on 1 August 2012, Peter Slaman applied for a hearing before the Environmental Review Tribunal with respect to the Renewable Energy Approval issued by the Director, Ministry of the Environment on 17 July 2012 to Capital Power GP Holdings Inc. (Capital Power).[123]

b. Background

Capital Power was granted approvals for wind power facilities in the Counties of Norfolk and Haldimand, pursuant to section 47.5 of the *Environmental Protection Act* (*EPA*).[124]

HWC and Slaman (the Appellants) alleged that engaging in the Project "will cause serious harm to human health."[125] Slaman further alleged that "the Project will cause serious and irreversible harm to plant life, animal life, or the natural environment due to bird collision mortality and bird habitat loss."[126]

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119 *Ibid* at 39.
120 *Ibid*.
121 *Ibid*.
122 *Haldimand Wind Concerns v Director, Ministry of the Environment*, Case Nos 12-098/12-100 (31 January 2013), online: ERT <http://www.ert.gov.on.ca/files/201302/00000300-CH1347B557O026-DB1343DDFOO026.pdf> [*Haldimand*].
123 *Ibid* at para 1.
124 RSO 1990, c E.19 [*EPA*]; *ibid* at para 1.
125 *Haldimand, ibid* at para 2.
126 *Ibid*.

c. Key Findings and Decision

The onus the Appellants must meet under section 145.2.1(3) of the *EPA* is proving that engaging in the renewable energy Project in accordance with the energy approval will cause the harm referred to in clause (2)(a) or (b) (that is serious harm to human health or "serious and irreversible harm to plant life, animal life or the natural environment)."[127]

The Tribunal adopted its previous findings in *Erickson v. Director (Ministry of the Environment),*[128] that the evidence must meet the civil standard of proof, in that "will cause" should be proven to the standard of "more likely than not."[129]

The Tribunal found that no evidence was called with respect to how the Project would cause serious harm to human health. The Tribunal also found that, at best, the evidence raised by Slaman with respect to whether the Project would cause serious and irreversible harm to plant life, animal life, or the natural environment, raised concerns of the interference with habitat due to soil compaction, which fell far short of the statutory test.[130]

The appeals were dismissed and the Director's decision was confirmed.[131]

H. WORLD TRADE ORGANIZATION

1. *CANADA — CERTAIN MEASURES AFFECTING THE RENEWABLE ENERGY GENERATION SECTOR*: *MEASURES RELATING TO THE FEED-IN TARIFF PROGRAM*

As legislatures throughout the world are introducing and implementing incentives to develop alternative energy, the interplay between these efforts and global trade is increasing in prominence. This decision is key to any examination of this interaction.

On 19 December 2012, the WTO issued panel reports in the disputes *Canada — Certain Measures Affecting the Renewable Energy Generation Sector* (complaint by Japan, DS412) and *Canada — Measures Relating to the Feed-in Tariff Program* (complaint by the European Union, DS426), respectively.[132]

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127 *Ibid* at para 106.
128 *Erickson v Director (Ministry of the Environment),* Case Nos 10-121/10-122 (18 July 2011), online ERT <http://www.ert.gov.on.ca/files/201107/00000300-AKT5757C7CO026-BGI54ED19RO026.pdf>.
129 *Haldimand, supra* note 122 at para 107.
130 *Ibid* at para 20.
131 *Ibid* at para 179.
132 *Canada — Certain Measures Affecting the Renewable Energy Generation Sector* (2012), WTO Doc WT/DS412/R (Panel Report), online: WTO <http://www.wto.org/english/tratop_e/dispu_e/412_426abr_a_e.pdf>; *Canada — Measures Relating to the Feed-in Tariff Program* (2012), WTO Doc WT/DS412/R (Panel Report), online: WTO <http://www.wto.org/english/tratop_e/dispu_e/412_426 abr_a_e.pdf> [Panel Reports].

a. Application

On 13 September 2010, Japan requested consultation with Canada regarding Canada's measures relating to domestic content requirements in Ontario's feed-in tariff program (the FIT). The US and European Union subsequently joined the consultations.

b. Background

FIT was established under Ontario's *Green Energy and Green Economy Act*[133] in 2009. It allowed power producers to sell renewable electricity (generated from wind, solar, hydro, biomass, biogas, and landfill gas) to the Ontario Power Authority under 20-year power purchase agreements. Electricity generated from these sources would be sold for prices at a premium over prices for electricity generated from other sources. In order to qualify for FIT, renewable energy Projects must include a certain percentage of each Project's equipment and services to be manufactured or sourced in Ontario.

On 13 September 2010, Japan appealed to the WTO to challenge the FIT content rules claiming that it violated three WTO conventions:

(1) *General Agreement on Tariffs and Trade*;[134]

(2) *Agreement on Trade-Related Investment Measures*;[135] and

(3) *Agreement on Subsidies and Countervailing Measures*.[136]

The EU subsequently initiated its own complaint on 11 August 2011. It argued that the FIT content rules breached GATT because the rules discriminated against foreign suppliers of equipment and supplies for domestic products.

c. Key Findings and Decision

The Panel found that FIT breached Canada's obligations under *GATT* and the international *TRIMs Agreement*, and discriminated against foreign suppliers of equipment and supplies. However, the Panel did not find that FIT violated the *SCM* and found that Japan was unable to establish that the local content rules constituted an illegal subsidy.[137] The Panel recommended that Canada bring its measures into conformity with its obligations under the *TRIMs Agreement* and *GATT*.[138]

133 SO 2009, c 12, s 25.35.
134 30 October 1947, 58 UNTS 187 (entered into force 1 January 1948) [*GATT*].
135 World Trade Organization (WTO), *Agreement on Trade-Related Investment Measures*, online: WTO <http://www.wto.org/english/docs_e/legal_e/18-trims.pdf> [*TRIMS Agreement*].
136 World Trade Law, *Agreement on Subsidies and Countervailing Measures*, online: World Trade Law <http://www.worldtradelaw.net/uragreements/scmagreement.pdf> [*SCM*].
137 Panel Reports, *supra* note 132 at paras 8.2-8.3.
138 *Ibid* at para 8.5.

d. Appeal

On 5 February 2013 and pursuant to articles 16.4 and 17 of the *Understanding on Rules and Procedures Governing the Settlement of Disputes* (*DSU*) and rule 20 of the *Working Procedures for Appellate Review*, Canada filed its notification of appeal of the WTO ruling.[139]

Canada sought a review of the conclusions that FIT breaches *GATT* and asserted that this conclusion was "in error and is based on erroneous findings on issues of law and legal interpretation,"[140] particularly the view that Ontario purchased renewable electricity "with a view to commercial resale."[141]

Further, Canada asserted that the Panel acted inconsistently with Article 11 of the *DSU* by failing to make objective assessment of the facts related to the issue, specifically relating to the finding that the resale of electricity was "commercial" in nature.

Canada also requested the Appellate Body to find that the Panel failed to find that the Government of Ontario did not purchase renewable electricity "with a view to use in the production of goods for commercial sale."[142]

On 6 May 2013, the WTO Appellate Body upheld the complaints asserted by the EU and Japan that the FIT program violated international trade rules. The Appellate Body confirmed that FIT discriminated against foreign suppliers as it mandates that a certain percentage of equipment components be domestically produced.[143] Although the Appellate Body ruled against some of the claims by Japan and the EU, it upheld the key findings of the original Panel that aspects of FIT violated *GATT* and the *TRIMS Agreement*. The Appellate Body requested that the offending provisions of the FIT program be brought into conformity with Canada's obligations under both Agreements.[144]

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139 WTO, *Understanding on Rules and Procedures Governing the Settlement of Disputes*, WTO Doc LT/UR/A-2/DS/U/1; WTO, *Working Procedures for Appellate Review*, WTO Doc WT/AB/WP/6 (2010); *Canada — Certain Measures Affecting the Renewable Energy Generation Sector* (2012), WTO Doc DS412/10 (Notification of an Appeal by Canada), online: WTO <http://trade.ec.europa.eu/doclib/docs/2013/march/tradoc_150726.pdf> and *Canada — Measures Relating to the Feed-in Tariff Program* (2012), WTO Doc DS426/9 (Notification of an Appeal by Canada), online: WTO <http://trade.ec.europa.eu/doclib/docs/2013/march/tradoc_150726.pdf>.

140 *Ibid* at 1.

141 *GATT*, *supra* note 134 at Part II, Article 111, s 8(a).

142 *Ibid*.

143 WTO, *Canada — Certain Measures Affecting the Renewable Energy Generation Sector and Canada — Measures Relating to the Feed-In Tariff Program*, WTO Doc WT/DS412/AB/R and WT/DS426/AB/R (6 May 2013), online: WTO <https://docs.wto.org/dol2fe/Pages/FE_Search/FE_S_S006.aspx?Query=(@Symbol=%20wt/ds412/ab/r*%20not%20rw*)&Language=ENGLISH&Context=FomerScriptedSearch&languageUIChanged=true#>.

144 *Ibid* at 141-43.

II. CANADIAN COURTS

A. FEDERAL COURT OF CANADA

1. *GITXAALA NATION V. THE MINISTER OF TRANSPORT, INFRASTRUCTURE, AND COMMUNITIES AND NORTHERN GATEWAY PIPELINES LIMITED PARTNERSHIP*[145]

This decision is significant as it provides guidance as to the intersection of obligations to consult and varying federal review processes. As the prominence of large scale federally regulated energy projects increases, examinations of this intersection will become critical.

a. Application

The Gitxaala Nation brought this application "seeking prerogative relief against the Minister of Transport, Infrastructure and Communities (the Minister) and the Northern Gateway Limited Partnership in connection with the ongoing [NEB] regulatory review of the North Gateway Pipeline Project."[146]

The Gitxaala Nation argued that its exclusion from participating in a federal interdepartmental review of marine safety factors relevant to the Northern Gateway Project (known as a TERMPOL review or TRP) constituted a breach of the federal Crown's duty to consult. As a result, the Gitxaala Nation sought "an order quashing the TRP report and directing the Minister to reopen the process to allow for meaningful consultation."[147]

b. Background

In this application "[t]he Northern Gateway Project proposes to build and operate dual oil and condensate pipelines along a 1,172 kilometer corridor from Bruderheim, Alberta to Kitimat, British Columbia." From Kitimat, oil can be exported and condensate can be imported using marine tankers. The cost of construction is estimated to exceed $5.5 billion and will support the export of 30 million tonnes of crude oil and the import of 11 million tonnes of condensate.[148]

The Gitxaala Nation reserves are primarily located immediately adjacent to the proposed marine shipping routes that will service the western terminus of the Gateway pipeline at Kitimat. The Gitxaala Nation provided evidence demonstrating its reliance on marine resources in the area proposed for the transit of marine tankers servicing the Gateway marine terminal at Kitimat.[149]

The Northern Gateway TRP was initiated in 2004 and the Gitxaala Nation expressed a desire to be included in the process. The purpose of the TRP was to objectively appraise

145 *Gitxaala Nation v The Minister of Transport, Infrastructure, and Communities and Northern Gateway Pipelines Limited Partnership*, 2012 FC 1336, 2012 CLB 32198.
146 *Ibid* at para 1.
147 *Ibid* at para 2.
148 *Ibid* at paras 4-6.
149 *Ibid* at paras 9-10.

operational ship safety, route safety, management, and environmental concerns associated with the construction and operation of the terminal.[150] The Minister of Transport wrote a letter to the Gitxaala Nation stating that its concerns should be addressed within the context of its participation before the Gateway Project joint review panel.[151]

c. Key Findings and Decision

The Court stated that a standard of correctness applied to determine whether a duty to consult arose in the circumstances. However for the determination of whether the framework established for consultation was sufficient or meaningful, a standard of reasonableness applied. The issue before the Federal Court was "whether the consultation framework proposed by the Crown … is a sufficient platform for consultation."[152] In other words, the issue was whether the duty to consult could be fulfilled by the opportunities available to Gitxaala to fully engage in the joint review panel process, rather than participate in the work of the TRP Committee.[153]

The Court commented that the Crown's duty of consultation must be "timely and meaningful and it must contribute to the ultimate goal of reconciliation."[154] The Court provided that the Crown had, from the beginning, acknowledged its duty to consult to all Aboriginal groups that may be affected by the Project. Further, the joint review panel process was sufficiently robust that any weakness in the TRP report could be addressed by the Gitxaala Nation and addressed by the joint review panel. The Court provided that the TRP was not a high level strategic decision that may have an impact of the Gitxaala Nation's long term interests.[155]

The Court concluded that the TRP process did represent a reasonable way to address First Nations' concerns. There was nothing to suggest that the joint review panel would not listen fairly to the Gitxaala Nation's concerns and reach to its own conclusions. There was no basis for the Court to conclude that a breach of the duty to consult, if any, could not be remedied by the joint review panel, or the Crown.[156]

The application was dismissed without costs.[157]

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150 *Ibid* at para 18.
151 *Ibid* at para 24.
152 *Ibid* at para 39.
153 *Ibid* at para 46.
154 *Ibid* at para 47.
155 *Ibid* at para 51.
156 *Ibid* at para 54.
157 *Ibid* at para 55.

B. ALBERTA COURT OF APPEAL

1. *MÉTIS NATION OF ALBERTA REGION 1 V. JOINT REVIEW PANEL*[158]

In addition to the consideration of the jurisdiction to consider the completeness of Crown consultation, this decision is instructive with respect to appeals of interlocutory decisions of quasi-judicial tribunals.

a. Application

The Métis Nation of Alberta Region 1, and others, representing the interests of various Metis people who live near the Jackpine mine, applied for leave to appeal an interlocutory decision of the Joint Review Panel (JRP) created to review the application for the Jackpine Mine Expansion Project.[159]

b. Background

The JRP concluded that it did not have jurisdiction to consider whether the Crown had complied with its obligation to consult with aboriginal peoples. This was an interlocutory decision and the hearing was still ongoing at the date of this decision.[160]

Shell Canada presently operates the Jackpine mine and applied to amend its licence to expand the mine to include adjacent property and to increase the capacity of the facility. This required approval from the ERCB and the *CEAA*.[161] To avoid duplication of regulatory review, the JRP was formed to consider the application and was required to consider Aboriginal issues as part of its mandate.[162]

The JRP issued the decision declining to consider certain constitutional questions.[163] The Métis Nation applied for leave to appeal numerous issues, namely surrounding the central issue of whether the JRP misinterpreted its statutory jurisdiction, or erred in law, or both in its interpretation of the *Energy Resources Conservation Act*[164] and the *Administrative Procedures and Jurisdiction Act*.[165]

c. Key Findings and Decision

The Court applied the test from *Berger v. Alberta (Energy Resources Conservation Board)* and concluded that it was not appropriate to grant leave to appeal as the answers to the jurisdictional questions posed would not affect the outcome of the hearing. The JRP clearly

158 *Métis Nation of Alberta Region 1 v Joint Review Panel*, 2012 ABCA 352, 539 AR 146 [*Métis Nation*].
159 *Ibid* at para 1.
160 *Ibid* at para 9.
161 *Ibid* at para 4.
162 *Ibid* at para 7.
163 *Ibid* at para 9.
164 RSA 2000, c E-10; *Métis Nation*, *ibid* at para 10.
165 RSA 2000, c A-3.

was not required to make any determination as to whether the Crown met its duty to consult; it was entitled to make the decision not to make a determination on this matter.[166]

The Court also concluded that it would be inappropriate to review the interlocutory decision prior to the completion of the hearing.

The applications for leave to appeal were dismissed.

2. *INTER PIPELINE FUND V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[167]

This decision provides guidance as to the adequacy of a tribunal's consideration of evidence and the adequacy of its reasons.

a. Application

Taylor Processing Inc. (Taylor) brought an application to the ERCB seeking approval for a proposed co-streaming Project at its Harmattan plant. Inter Pipeline Fund and BP Canada objected to the application.[168] The ERCB concluded that the Project was in the public interest and approved the Project.[169]

Inter Pipeline was granted leave to appeal the ERCB's decision and the Court of Appeal was to determine whether the ERCB (1) gave adequate reasons explaining its assessment of the critical evidence; and (2) breached its duty of procedural fairness.[170]

b. Background

Taylor intended to alter its existing gas processing facility and divert natural gas liquids from the gas, and return the residue gas to the common stream downstream from Inter Pipeline's straddle plant at Cochrane (the only straddle plant on the NOVA Gas Transmission Ltd. Western Alberta System). BP Canada Energy Company and BP Canada Energy Resources Company (collectively, BP), purchase natural gas liquid production from the Cochrane plant, own a pipeline which transports that production to Edmonton, and own substantial straddle plant capacity at Empress on NOVA's eastern leg of its Alberta system.[171]

The ERCB set a hearing timetable and both Inter Pipeline and BP made information requests of Taylor. Taylor initially stated that it would rely upon a gas supply forecast prepared in July 2009 by Ziff Energy Group. BP took issue with the adequacy of Taylor's responses and asked for further and better responses, which the ERCB denied because it was of the view that BP had "sufficient information" to proceed with the hearing. Before the

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166 *Métis Nation*, *supra* note 158 at para 26.
167 *Inter Pipeline Fund v Alberta (Energy Resources Conservation Board),* 2012 ABCA 208, 533 AR 331, leave to appeal to SCC refused, 35015 (17 January 2013).
168 *Ibid* at para 7.
169 *Ibid* at para 11.
170 *Ibid* at para 18.
171 *Ibid* at paras 3-5.

hearing, Taylor submitted a new gas supply forecast prepared by TransCanada and disclosed that it was not going to rely upon the July 2009 Ziff report. Taylor's witnesses were unable to answer questions on the forecasts relied upon by Taylor. Therefore Inter Pipeline and BP had no opportunity to challenge the conclusions put forward by Taylor.[172]

Inter Pipeline also filed its own gas supply forecast into evidence. Rather than accepting one forecast, the ERCB concluded that the answer would lie somewhere between the forecast submitted by Taylor and the forecast submitted by Inter Pipeline.[173]

The ERCB approved Taylor's application and Inter Pipeline applied for leave to appeal alleging that the ERCB gave inadequate reasons. Leave was granted.[174]

c. Key Findings and Decision

At the Court of Appeal, the majority found that the adequacy of reasons provided by the ERCB was to be reviewed on a reasonableness standard, and concluded that the ERCB's reasons were "within the range of acceptable and rational conclusions."[175] Further, the reasons contained the required "justification, transparency and intelligibility within the decision-making process."[176] The majority found that the ERCB gave elaborate reasons for deciding that the Project would result in incremental recovery in certain scenarios, and that the ERCB reasonably emphasized the long-term prospects for enhanced natural gas liquid recovery.[177]

With respect to procedural fairness, the majority commented that the ERCB has the power to determine whether the information put forward by an applicant is adequate in that it will enable other parties to make an informed case against an application. They held that BP was entitled to put in its own evidence, to cross-examine, and make final submissions. BP declined to do so.[178] Therefore, the majority concluded that procedural fairness was not compromised in the circumstances.[179]

The appeal was dismissed and leave to appeal to the Supreme Court of Canada was denied.[180]

3. *SHAW V. ALBERTA (ALBERTA UTILITIES COMMISSION)*[181]

Although the Alberta government has since rescinded the legislation giving rise to determinations of certain transmission facilities as being CTI and, therefore, exempt from a preliminary needs assessment by the AUC, the Court's consideration of the AUC's public interest mandate here is significant.

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172 *Ibid* at paras 7-8.
173 *Ibid* at para 8.
174 *Ibid* at para 18.
175 *Ibid* at para 48.
176 *Ibid* at para 26.
177 *Ibid* at para 48.
178 *Ibid* at para 70.
179 *Ibid* at para 71.
180 *Ibid* at para 72. See also *supra* note 166.
181 *Shaw v Alberta (Alberta Utilities Commission)*, 2012 ABCA 378, 539 AR 315.

a. Application

The appellants appealed the AUC approval to construct and operate the Heartland transmission line Project. The AUC "concluded that its consideration of project impacts was significantly constrained for critical infrastructure projects."[182]

b. Background

As background to this application, '[i]n November 2009, the Alberta legislature enacted the *ESAA* … which modified the regulatory approval process for some major electrical transmission projects," including the Heartland Project. A transmission development could be designated as CTI either by the legislature or by order of the Lieutenant Governor-in-Council if it was "required to meet the needs of Alberta."[183]

The appellants, landowners affected by the Heartland Project, argued that despite the introduction of CTI, the AUC continues to enjoy a broad public interest mandate when considering transmission facility applications generally and that mandate was not restricted for CTI Projects under the new legislation.[184]

The Alberta Court of Appeal was asked to determine whether, in designating a transmission line as CTI the legislature intended to remove (or limit the scope of) the AUC's public interest inquiry in approving the transmission line.[185]

c. Key Findings and Decision

The Court applied fundamental statutory interpretation principles, analyzed how the various pieces of the legislation operate together, and ascertained the legislative intent and overall purpose of the entire legislative scheme for CTI approvals.[186]

The Court concluded that the purpose of the *ESAA* was to eliminate the need assessment from the AUC's process for projects designated as CTI. Further, the Court held that the AUC retained "jurisdiction to hear and consider facility applications with respect to those projects, and must consider the public interest as part of a facility approval."[187]

The appeal was dismissed and the interpretation of the AUC was confirmed.[188]

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182 *Ibid* at para 6.
183 *Ibid* at para 5.
184 *Ibid* at para 7.
185 *Ibid* at para 2.
186 *Ibid* at paras 32-38.
187 *Ibid* at para 40.
188 *Ibid* at para 41.

C. ONTARIO SUPERIOR COURT

1. *SKYPOWER CL I LP V. MINISTER OF ENERGY (ONTARIO)*[189]

This judicial review application respecting the FIT program provides insight into how courts may consider challenges to revisions to administrative process by government.

a. Application

The applicants sought "declarations that the respondents acted unreasonably in failing to process applications in accordance with the Ontario Power Authority's ('OPA') own rules; to declare that the Minister of Energy's new Directions are unfair, discriminatory, and *ultra vires* the enabling legislation; and to order the Minister to direct the OPA to process existing applications in accordance with the Feed-In Tariff ('FIT') Program Rules 1.0."[190]

The applicants also sought, if the Court decided to reserve its decision on this application (as it did), an order prohibiting the OPA from accepting new applications pursuant to the FIT Rules 2.0 and "awarding contracts pursuant to the FIT Rules 2.0, until a decision was rendered."[191]

b. Background

The applicants comprise 118 limited partnerships all owned by the same persons and similarly affected by the actions of the respondents; they all submitted a large number of applications under the FIT program.[192]

The Ontario government brought into force the *Green Energy and Green Economy Act, 2009* and amendments to the *Electricity Act, 1998* to provide for the development of the FIT program open to projects that produce electricity from renewable sources including wind, solar photovoltaic, bioenergy, and waterpower up to 50 megawatts (MW).[193]

On 24 September 2009, the OPA issued FIT Rules 1.0 defining the specific procedure pursuant to which applications would be received and processed for FIT contracts. There were over 2,300 applications submitted by large-scale project developers (including the applicants) to supply over 14,000 MW of renewable energy. This "signalled the need for a long-term plan for the supply of renewable energy to ensure that connection capacity was sufficiently economic and feasible to support the FIT program, and that grid expansion would be done reasonably as ratepayers would bear the considerable cost of expanding the electricity grid)."[194]

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189 *Skypower CL 1 LP v Ontario (Minister of Energy)*, 2012 ONSC 4979, 220 ACWS (3d) 346 [*Skypower*].
190 *Ibid* at para 1.
191 *Ibid* at para 2.
192 *Ibid* at para 3.
193 *Green Energy and Green Economy Act, 2009*, SO 2009, c 12; *Electricity Act, 1998*, SO 1998, c 15; *Skypower, supra* note 186 at paras 4, 8.
194 *Skypower, ibid* at para 22.

The FIT program review began on 31 October 2011. At that time, the OPA announced that FIT applications would not be processed during the review and that amendments to the FIT Rules as a result of the review would apply to all applications that had not received a FIT contract by 31 October 2011.[195] On 10 August 2012, FIT Rules 2.0 were posted; the applications that were received by 31 October 2011 but awaiting review could be resubmitted under FIT Rules 2.0.

The applicants brought an application for judicial review claiming that significant time and investment had been expended to prepare and complete eligible applications under FIT Rules 1.0.[196] The applicants provided that it was "not feasible for them to simply withdraw and resubmit their applications" under the new rules.[197]

c. Key Findings and Decision

The Court rejected the argument that the implementation of the FIT Rules 2.0 was *ultra vires* the *Electricity Act, 1998*. The Court provided that, "if the Minister had the legislative authority to direct the OPA to implement the FIT program along with FIT Rules 1.0, then he has the legislative authority to direct the OPA to implement any amendments to, or variations of, the program and the rules."[198] The FIT Rules 2.0 do not go outside of the enabling legislation that grants the Minister broad discretion to develop the FIT program.[199]

The Court also rejected the argument that the application process for the FIT program and the contents of the FIT Rules 1.0 are equivalent to a tender process. The FIT program does not involve fixed specifications for a contract where the main issue is the question of price to be charged for the work to be performed; the applicant would only receive a contract if it met the application criteria and if the project passed the connection availability assessment process; and grid availability was a precondition to a FIT contract subject to required impact assessments. There were too many variables to the success of any application and whether a contract was awarded.[200] The Court provided that the FIT program was a vehicle to deliver Government policy on renewable energy, not solely a commercial arrangement devoid of any social or public policy.[201] Therefore, there was no intention by the OPA or the Minister to create contractual obligations through the submission of a proposed project under the FIT program.[202]

With respect to legitimate expectations, the Court concluded that there was little that would constitute a representation that was "clear, unambiguous and unqualified" to create a legitimate expectation that the criteria for the FIT program or the process under it would not change.[203] Further, the applicants did not have a legitimate expectation that their applications would be processed within six months purely because the FIT Rules 1.0

195 *Ibid* at para 29.
196 *Ibid* at para 35.
197 *Ibid* at para 45.
198 *Ibid* at para 50.
199 *Ibid*.
200 *Ibid* at para 56.
201 *Ibid* at para 69.
202 *Ibid* at para 61.
203 *Ibid* at para 63.

provided that "time is of the essence."[204] The OPA had been overwhelmed with the applications received and had to set new timeframes.[205]

The Court also rejected the applicants' assertion that they gained vested rights through the FIT program when they made their applications. Based on the facts, the applicants did not acquire any vested rights of a type that were tangible, concrete, and distinctive; at most, they had a prospect of obtaining one or more contracts to provide renewable energy to the province.[206]

Finally, the Court rejected the applicants' argument that the FIT Rules 2.0 offended the principle against retroactive application of legislation. The applicants did not have any rights under the FIT program. Instead they have an opportunity to have their applications considered. The Court provided that the rules that apply to those applications are the rules that are in effect when the consideration occurs.[207] While the Court conceded that it may "seem unfair when rules are changed in the middle of a game, that is the nature of the game when one is dealing with government programs."[208]

The application for judicial review was dismissed.[209]

III. LEGISLATION AND REGULATION

A. FEDERAL

1. REGULATIONS UNDER THE *CANADIAN ENVIRONMENTAL ASSESSMENT ACT, 2012*

The Government of Canada released regulations related to *CEAA 2012*.[210] They set out the designated projects that require environmental assessments, the information required in project descriptions, and the types of costs incurred by the Canadian Environmental Assessment Agency (CEAA) that may be recovered from project supporters.

a. *Regulations Designating Physical Activities*

Prior to the introduction of these regulations, proposed projects had to undergo environmental assessment when the proponent was a federal entity, the project involved federal funds or federal land, or when federal approval was required. Under the *CEAA, 2012*, the *Regulations Designating Physical Activities* will trigger the need for projects to undergo environmental assessments.[211]

The Schedule to the *Regulations Designating Physical Activities* sets out the projects or activities that are subject to reviews conducted by the CEAA, who will screen projects to

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204 *Ibid* at para 69.
205 *Ibid* at para 71.
206 *Ibid* at para 77.
207 *Ibid* at para 82.
208 *Ibid* at para 84.
209 *Ibid* at para 85.
210 *Supra* note 24.
211 *Regulations Designating Physical Activities*, SOR/2012-147.

determine whether they will cause adverse environmental effects or public concerns related to those effects.[212] If there may be adverse effects, the CEAA will refer the project for a full environmental assessment.[213] The Schedule also sets out some projects that are to be reviewed by either the Canadian Nuclear Safety Commission or the NEB. These projects automatically require a full environmental assessment.[214]

b. *Prescribed Information for the Description of a Designated Project Regulations*

On 6 July 2012, the Government of Canada registered the *Prescribed Information for the Description of a Designated Project Regulations* under *CEAA, 2012*. [215] The *Regulations* to *CEAA, 2012* set out the information that is required in the description of designated projects for which an environmental assessment is required.[216]

The essential difference between the old and new regulations is how they relate to environmental effects. Environmental effects that must be taken into account are now limited to areas of federal legislation, such as the effects on fish and fish habitat, aquatic species, migratory birds, and changes in the environment that may occur as a result of carrying out the project on federal lands.[217]

The *Regulations* also require that "information be provided on the effects on Aboriginal peoples of any changes to the environment that may be caused as a result of carrying out the project."[218]

2. *REDUCTION OF CARBON DIOXIDE EMISSIONS FROM COAL-FIRED GENERATION OF ELECTRICITY REGULATIONS*

On 30 August 2012, the Government of Canada registered the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* under the *Canadian Environmental Protection Act*.[219] Certain sections of the *Regulations* come into force at different times.[220]

The *Regulations* establish a regime for the reduction of CO_2 emissions resulting from the production of electricity through thermal energy using coal as a fuel, whether in conjunction with other fuels or not.[221] The *Regulations* set a stringent performance standard for new coal-fired units that start producing electricity commercially on or after 1 July 2015 and for units that have reached the end of their useful life. Units that have reached the end of their useful

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212 *Ibid*, ss 2-4. See section 19 of *CEAA 2012* for factors to be considered in determining whether an environmental assessment of a designated project must be carried out (*supra* note 24).

213 *CEAA 2012*, *ibid*, s 22.

214 *Overview: Canadian Environmental Assessment Act, 2012*, online: CEAA <http://www.ceaa-acee.gc.ca/default.asp?lang=En&n=16254939-1>.

215 *Prescribed Information for the Description of a Designated Project Regulations*, SOR/2012-148.

216 *Ibid*, s 1.

217 *Ibid*, s 1 at 17-18.

218 *Ibid*, s 1 at 19.

219 *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, SOR/2012-167.

220 *Ibid*, s 29.

221 *Ibid*, s 1.

life are those that have reached 50 years since starting to produce electricity commercially. This performance standard aims to encourage a transition towards lower or non-emitting types of generation such as renewable energy or natural gas.

The performance standard is set at 420 tonnes per gigawatt hour (t/GWh) and will come into force on 1 January 2015. An owner or operator of a new unit or an old unit "must not emit, on average, with an intensity of more than 420 tonnes of CO_2 emissions from the combustion of fossil fuels in the unit for each [gigawatt] of electricity produced by the unit during a calendar year."[222]

New and end-of-life units that incorporate technology for carbon capture and storage may apply for an exemption from the performance standard until 2025. The exemption is only available if the carbon capture system is economically and technically feasible and an implementation plan is in place that provides a description of the work to be done and the steps necessary to capture and store carbon.[223]

All coal-fueled units, as defined under the *Regulations*, must be registered with the Minister. For existing or old units, the responsible person for the unit must have registered on or before 1 February 2013. For new units, the responsible person must register on or before 30 days after the date on which a unit begins to produce energy for sale to an electric grid.[224] The responsible person for the unit must also send the Minister an annual report for each new unit, old unit, substituted unit, and unit tied to an old unit with a temporary exemption.[225]

3. *JOBS, GROWTH AND LONG-TERM PROSPERITY ACT*

On 29 June 2012, An Act to Implement Certain Provisions of the Budget Tabled in Parliament on 29 March 2012 and other Measures (*Jobs, Growth and Long-term Prosperity Act*) was given Royal Assent.[226]

Part 3 of the *Jobs, Growth and Long-term Prosperity Act* contains amendments to legislation that relate to responsible resource development.

a. Division 1 - *Canadian Environmental Assessment Act, 2012*

Division 1 of Part 3 enacts *CEAA 2012*, which establishes a new federal environmental assessment regime.[227] As discussed previously, this *Act* requires assessments to be conducted for projects designated by regulation or by the Minister of Environment.[228] These assessments will determine whether the projects are likely to cause significant adverse environmental effects that fall within the authority of Parliament, or that are linked or

222 *Ibid*, s 3(1).
223 *Ibid*, s 9.
224 *Ibid*, s 4.
225 *Ibid*, s 15.
226 *Jobs, Growth and Long-term Prosperity Act*, *supra* note 2.
227 *CEAA 2012*, *supra* note 24.
228 *Ibid*, ss 13-14.

necessarily incidental to a federal authority's exercise of a power or performance of a duty or function that is necessary for carrying out the Project.[229]

The assessments are to be conducted by the CEAA, the Canadian Nuclear Safety Commission, the NEB, or a review panel established by the Minister.[230] After concluding an assessment, a decision statement will be issued to the project proponent who must comply with the conditions set out in the statement.[231]

This *Act* also provides for the federal government and other jurisdictions to cooperate by enabling the delegation of environmental assessment,[232] the substitution of the process of another jurisdiction for an environmental assessment under *CEAA 2012*,[233] and the exclusion of a project from the application of the *Act* when there is an equivalent assessment required by another jurisdiction.[234]

Finally, *CEAA 2012* provides that federal authorities are not to take certain measures regarding carrying out projects on federal lands or outside Canada unless the projects are not likely to cause significant adverse environmental effects.[235]

This Division also makes amendments to the *Environmental Violations Administrative Monetary Penalties Act*,[236] consequential amendments to other acts, and repeals the earlier *Canadian Environmental Assessment Act*.[237]

b. Division 2 - *National Energy Board Act*

The *NEB Act* is amended in this Division to allow the Governor in Council to make decisions regarding the issuance of certificates for major pipelines.[238] It establishes time limits for regulatory reviews under the *NEB Act*[239] and enhances the powers of the National Energy Board Chairperson and the Minister responsible for the *Act* to ensure that these reviews are conducted in a timely manner.[240]

The *NEB Act* was also amended to allow the National Energy Board to exercise federal jurisdiction over navigation in respect of pipelines and power lines that cross navigable waters. Finally, the *NEB Act* establishes an administrative monetary penalty system, which will be discussed further below.[241]

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229 *Ibid*, s 15.
230 *Ibid*, s 22.
231 *Ibid*, s 31(3).
232 *Ibid*, s 26.
233 *Ibid*, s 32.
234 *Ibid*, s 37.
235 *Ibid*, s 7.
236 *Environmental Violations Administrative Monetary Penalties Act*, SC 2009, c 14.
237 *Supra* note 50.
238 *Supra* note 2.
239 *Ibid*, ss 52, 58, 58.16.
240 *Ibid*, s 6.
241 *Ibid*, s 2 (see the definition of "penalty").

c. Division 5 - *Fisheries Act*

The *Fisheries Act* was amended to focus on the protection of fish that support commercial, recreational or Aboriginal fisheries, rather than preventing any activity that results in the harmful alteration, disruption, or destruction of fish habitat.[242]

The amendments grant new powers to the Minister in issuing approvals for habitat impacts (such as consideration of economic factors or to allow habitat impacts from development and projects).[243] The Minister is able, pursuant to the amendments, to enter into agreements with provinces and other bodies,[244] provide for the control and management of aquatic invasive species,[245] clarify and expand the powers of inspectors,[246] and permit the Governor in Council to designate another Minister as the Minister responsible for the administration and enforcement of sections 36(3) to (6) of the *Fisheries Act* in relation to the subject matter set out by an order.[247]

The key change in the amendments is what constitutes "serious harm to fish." If one of the three protected fisheries (commercial, recreational, or Aboriginal) is damaged permanently, the prohibitions under the amended *Act* will be triggered.[248]

d. Division 7 - *Species at Risk Act*

The *Species at Risk Act*[249] was amended to allow for authorizations to be issued with a longer term,[250] to clarify the authority that may renew the authorizations,[251] and to make compliance with the conditions of permits enforceable.[252] The amendments also provide authority to make regulations respecting time limits for issuance and renewal of permits under the *Species at Risk Act*. Section 77 was amended to ensure that the NEB would be able to issue a certificate when required to do so by the Governor in Council pursuant to section 54(1) of the *NEB Act*.[253]

4. NEB *ADMINISTRATIVE MONETARY PENALTIES REGULATIONS*

The NEB developed the *Administrative Monetary Penalties Regulations* that are intended to encourage safety and environmental protection.[254]

The NEB requires pipeline companies to anticipate, prevent, manage and mitigate potentially dangerous conditions with their pipelines. The administrative monetary penalties

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242 RSC 1985, c F-14.
243 *Ibid*, s 6.
244 *Ibid*, s 4.1.
245 *Ibid*, s 43(3).
246 *Ibid*, s 38(1).
247 *Ibid*, s 43.2(1).
248 *Ibid*, s 35(1).
249 *Species at Risk Act*, SC 2002, c 29.
250 *Ibid*, s 73(11).
251 *Ibid*, s 78.1.
252 *Ibid*, s 97.
253 *Ibid*, s 77(1.1).
254 *Administrative Monetary Penalties Regulations* (Canada Nuclear Safety Commission), (2013) C Gaz 1, 245.

will allow the NEB to penalize companies or individuals for non-compliance with the *NEB Act* or its regulations (intended to encourage safety and environmental protection). The *Regulations* came into force on 3 July 2013 along with provisions of the *NEB Act* that formed the legislative framework for the new administrative monetary penalty system.[255]

The *Regulations* provide that any contravention of any order or decision under the *NEB Act* is designated as a violation.[256] The *Regulations* set out the penalties for each violation[257] and include the total gravity value on a scale of minus three to five or more in the calculation of the penalty for the particular violation. Total gravity value is ascertained by taking into account certain criteria such as whether the person who committed the violation had committed other violations in the previous seven years, whether the person derived any competitive or economic benefit, whether the person made reasonable efforts to mitigate or reverse the violation's effects, and so on.[258] The *Regulations* also provide for service of documents required under section 139, 144 or 147 of the *NEB Act* (such as a notice of violation or a copy of the determination of a review).[259]

Schedule 1, Part 1 sets out various things that constitute violations under the *NEB Act* including, but not limited to: construction or operation of a pipeline without a certificate; construction or operation of an interprovincial or international power line without leave; and failure to do as little damage as possible in exercising the powers granted.[260] Part 2 provides what constitutes a violation under the *Onshore Pipelines Regulations, 1999,* including failure to ensure that a pipeline is designed, constructed, operated or abandoned as prescribed; failure to appoint an accountable officer and to ensure that the management system is established, implemented and maintained as prescribed; failure to complete an annual report and submit a statement as prescribed, failure to take reasonable steps to ensure that maintenance activities do not create a hazard to the public or the environment, and so on.[261]

Part 3 of Schedule 1 provides violations under the *National Energy Board Processing Plant Regulations*,[262] Part 4 of Schedule 1 provides violations under the *National Energy Board Pipeline Crossing Regulations, Part I*,[263] Part 5 provides violations under the *National Energy Board Pipeline Crossing Regulations, Part II*,[264] and Part 6 provides violations under the *Power Line Crossing Regulations*.[265]

Schedule 2 provides the penalties for each violation which vary depending on whether the violation is a Type A or Type B violation (as designated in Schedule 1) and the gravity level applied pursuant to subsection 4. The penalties range from $250 to $25,000 for individuals and $1,000 to $100,000 for any other person.[266]

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255 SOR/2013-138 [*Regulations*].
256 *Ibid* , s 2.
257 *Ibid*, Schedule 2.
258 *Ibid*, s 4(2).
259 *Ibid*, s 5.
260 *Ibid*, Schedule 1, Part 1.
261 *Ibid*, Schedule 1, Part 2; *National Energy Board Onshore Pipeline Regulations*, SOR/99-294.
262 SOR/2003-39.
263 SOR/88-528.
264 SOR/88-529.
265 SOR/95-500.
266 *Regulations*, *supra* note 255, Schedule 2.

5. NEB *ONSHORE PIPELINE REGULATIONS*

The NEB's *Regulations Amending the Onshore Pipelines Regulations* were published in the *Canada Gazette*, Part II, on 10 April 2013.[267] These *Regulations* clarify the requirements for regulated pipelines regarding management systems to protect the public, workers, and environment. The *Regulations* also rename the *Onshore Pipeline Regulations, 1999* to the *National Energy Board Onshore Pipeline Regulations*.[268]

Section 6 provides that when a company designs, constructs, operates, or abandons a pipeline, it shall do so in a way that ensures the safety and security of the public and the company's employees, the safety and security of the pipeline, and the protection of property and the environment.[269]

Section 6.1 requires a company to establish, implement, and maintain a management system that: is systematic, explicit, comprehensive, and proactive; integrates the company's operational activities and technical systems; applies to all of the company's activities involving the design, construction, operation, or abandonment of a pipeline; ensures coordination between various programs (including the emergency management program, safety management program, environmental protection program, etc.); and corresponds to the size of the company, to the scope, nature, and complexity of its activities, and the risks associated with those activities.[270]

Section 6.2 requires a company to appoint an officer to be accountable for its management systems, its safety culture, and the achievement of outcomes related to public safety, and environmental protection. This accountable officer must sign an annual report describing the performance of the company's management system and any actions taken during the year to correct any deficiencies identified by a quality assurance program established under section 6.5 (section 6.5 sets out detailed processes that the company must establish as part of its management system).[271]

6. NEB APPLICATION TO PARTICIPATE FORM

The NEB changed how Canadians can participate in a pipeline hearing in early April 2013. The first test of the new procedure for applying to participate is the Enbridge Line 9 reversal, which was established when the NEB issued Procedural Update No. 1 on 4 April

267 *Regulations Amending the Onshore Pipeline Regulations, 1999*, (2013) C Gaz 11, 808.
268 *Ibid*, s 1.
269 *Ibid*.
270 *Ibid*.
271 *Ibid* at para 6.6.

2013.[272] Those seeking the opportunity to participate in the hearing process were required to submit the Application to Participate form by 19 April 2013.[273]

The Application to Participate form includes ten pages of questions for the applicant to answer. Of note is that the applicant must establish that they (or the persons they are representing) are directly affected by the proposed project, or have relevant information or expertise, or both. However, the Application to Participate form does not provide guidelines on what constitutes "directly affected."[274] The applicant must also review the list of issues for the hearing and provide which issues they wish to speak to, including an explanation of the information that will be provided relating to the issue, how that information will be provided (the format), and an explanation of why the information is relevant.[275]

B. ALBERTA[276]

1. AMENDMENTS TO THE *ELECTRIC UTILITIES ACT*

On 23 October 2012, Bill 8, the *Electric Utilities Amendment Act*, passed through first reading, and was later given Royal Assent on 10 December 2012.[277] Bill 8 provides that all future transmission line projects require full assessment of the need for each project and subsequent approval of same by the Alberta Utilities Commission (AUC), not the provincial Cabinet.[278] This overrides Bill 50, the *ESAA*, which provided that Cabinet would have the right to designate certain transmission infrastructure as CTI and that for any CTI designated facility there would be no review by the AUC of the need for the facility.[279]

272 Sheri Young (Secretary for the Board), *Update No 4: Letter to Chantal Robert, Margery Fowke, and Doug Crowther* (4 April 2013), online: National Energy Board <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/92263/790736/890819/918701/941089/A5-1_-_Procedural_Update_No._1_-_List_of_Issues_and_Application_to_Participate_Form_Hearing_Order_OH-002-2013_Line_9B_Reversal_and_Line_9_Capacity_Expansion_Project_Enbridge_Pipelines_Inc._-A3G6J4_?nodeid=941090&vernum=0&redirect=3>.

273 *Hearing Order OH-002-2013 — Enbridge Pipelines Inc Application for the Line 9B Reversal and Line 9 Capacity Expansion Project*, Letter from Sheri Young to Chantal Robert, Margery Fowke & Doug Crowther (4 April 2013), online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/92263/790736/890819/918701/941089/A5-1_-_Procedural_Update_No._1_-_List_of_Issues_and_Application_to_Participate_Form_Hearing_Order_OH-002-2013_Line_9B_Reversal_and_Line_9_Capacity_Expansion_Project_Enbridge_Pipelines_Inc._-A3G6J4_?nodeid=941090&vernum=0>.

274 "Application to Participate Form," online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/ nbrdgln9brvrsl/frm/pplctnprtcpt-eng.pdf>.

275 *Ibid*.

276 Alberta's *Responsible Energy Development Act*, SA 2012, c R-17.3 and its regulations are not canvassed in this article as they have been covered in great detail in another article also appearing in this edition of the *Alberta Law Review* entitled *Federal and Alberta Energy Project Regulation Reform — at What Cost Efficiency?*

277 Bill 8, *Electric Utilities Amendment Act*, 1st Sess, 28th Leg, Alberta, 2012 (assented to 10 December 2012), SA 2012, c 6.

278 *Ibid*, s 41.3.

279 *Supra* note 103.

2. ENACTMENT OF THE *PROPERTY RIGHTS ADVOCATE ACT*

On 18 December 2012, the Alberta Government proclaimed the *Property Rights Advocate Act*.[280] The *PRAA* is a direct response to the Property Rights Task Force Report, issued in February 2012.[281]

The *PRAA* provides a framework to support property owners in protecting their ownership rights. The Preamble to the *PRAA* provides that land owners should be consulted about proposed legislation that affects their property rights, the public information about property rights that should be readily available, that consultation should be conducted in advance of projects to ensure owners are aware of their rights, and that land owners should be properly compensated where their lands are expropriated and that they have recourse to tribunals such as the Land Compensation Board.[282]

The *PRAA* establishes a Property Rights Advocate Office, which includes the Property Rights Advocate who is responsible for the following:

(1) dissemination of independent and impartial information about property rights to the public (such as land owners' rights to compensation where land is expropriated);

(2) providing assistance to people in selecting appropriate resolution mechanisms (such as the courts) where their concerns may be addressed;

(3) providing assistance to expropriating authorities;

(4) reviewing complaints relating to an expropriation or a compensable taking of a person's land (made pursuant to the *PRAA*) and preparing a report setting out the findings or recommendations after a review of the complaint; and

(5) performing any other functions set out in the regulations.[283]

The Property Rights Advocate is also required to prepare an annual report summarizing the activities of the Office and setting out any recommendations relating to property rights that the Advocate considers appropriate. The report will be submitted to the speaker of the Legislative Assembly.[284]

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280 *Property Rights Advocate Act*, SA 2012, c P-26.5 [*PRAA*].
281 *Province responds to Property Rights Task Force recommendations* (21 February 2012), online: Government of Alberta <http://alberta.ca/acn/201202/31977A14B8487-D23C-0921-4216F4A86AD2CB3E>.
282 *PRAA*, *supra* note 280, Preamble.
283 *Ibid*, s 3(4).
284 *Ibid*, s 5.

3. LOWER ATHABASCA REGIONAL PLAN — *ALBERTA LAND STEWARDSHIP ACT*

On 22 August 2012, the Lieutenant Governor in Council authorized the Lower Athabasca Regional Plan (LARP) recommended by the Alberta Minister of Environment and Sustainable Resource Development pursuant to section 4 of the *Alberta Land Stewardship Act*.[285] The LARP was developed under the auspices of Alberta's Land-use Framework and the *Alberta Land Stewardship Act*, and by using a three phase consultation process gathering input on the region's issues, feedback on the advice from the Lower Athabasca Regional Advisory Council, and feedback on the Government of Alberta's draft Lower Athabasca Integrated Regional Plan.[286] The purpose of the LARP is to set the stage for robust growth, vibrant communities, and a healthy environment within the Lower Athabasca region over the next 50 years.[287] The LARP has a direct impact on oils sands development given the geography it covers.

The LARP implements three frameworks to manage cumulative effects in the region: the Air Quality Plan,[288] the Surface Water Quality Plan,[289] and the Groundwater Plan.[290] These plans outline monitoring, evaluation and reporting requirements, set early warning triggers to determine the need for action, and identify what actions may be taken.

The LARP uses management frameworks, which is a new approach to accomplish cumulative effects management. Environmental limits and triggers are established. The limits set boundaries in the system that are not to be exceeded, while triggers are used as warning signals for evaluation, adjustment and innovation. The aim with this approach is that trends are to be identified and assessed, regional limits are not to be exceeded and that the air and water remain healthy for the region's environment and its residents.[291]

4. *SECURITY MANAGEMENT REGULATION*

On 19 December 2012, the Government of Alberta filed the *Security Management Regulation*[292] under the *AUC Act*. This regulation provides various security measures to be established for critical facilities (defined as gas utility pipelines that are named in critical infrastructure lists in the Alberta Counter Terrorism Crisis Management Plan established under the *Emergency Management Act*[293]).

Generally, a licensee of a critical facility must establish security measures and respond to threats relating to the critical facility in accordance with practices outlined in the Alberta Counter Terrorism Crisis Management Plan.[294] The *Security Management Regulation* also

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285 SA 2009, c A-26.8; OC 268/2012, (2013) A Gaz 1, 20 [OC 268/2012].
286 OC 268/2012, *ibid*, Appendix, 2.
287 *Ibid*.
288 *Ibid* at 48-50.
289 *Ibid* at 51-54.
290 *Ibid* at 55-57.
291 *Ibid* at 24, 27.
292 Alta Reg 230/2012.
293 RSA 2000, c E-6.8.
294 *Security Management Regulation*, *supra* note 268, s 2(1).

allows the AUC to take steps, including ordering that a licensee shut down a gas utility pipeline, if the threat of terrorist activity is high or imminent.[295]

C. SASKATCHEWAN

1. AMENDMENTS TO THE *ENVIRONMENTAL ASSESSMENT ACT*[296]

The purpose of the *Environmental Assessment Act* (*EAA*) is to ensure that economic development moves forward with environmental safeguards to protect the environment and public health. The Government of Saskatchewan moved to a results-based regulatory model, and the amendments were made to align with this move.[297]

The *EAA* requires that a proponent receives the Minister of Environment's approval before proceeding with a development that is likely to have significant environmental implications. If the Minister makes a determination that the proposed undertaking is not a "development," ministerial approval to proceed is not required.[298] In making the determination of whether to approve a development, the Minister may cause an information meeting to be conducted and may appoint people to conduct an inquiry with respect to the development.[299]

If the Minister approves a development, the proponent must proceed in accordance with the terms and conditions of ministerial approval.[300] A proponent may submit a proposed change to the Minister if there is a change in the development that does not conform to the terms or conditions contained in the ministerial approval. The Minister may accept the change, refuse the change, or may direct the proponent to follow the procedure for ministerial approval as provided for in the *EAA*.[301]

D. QUEBEC

1. *ENVIRONMENT QUALITY ACT*

Amendments to the *Environment Quality Act*[302] provide the government with new measures to ensure compliance with the *EQA* by including a new system of administrative penalties, increasing penal sanctions, expanding functionaries' inspections and their ability to make orders, and imposing criminal and civil liability on directors and officers of legal persons, partnerships, and associations

If the *EQA* is contravened, administrative penalties may be imposed by "a person designated by the Minister." Depending on which section of the *EQA* is breached, penalties

295 *Ibid*, s 3.
296 *Environmental Assessment Act*, SS 1979-80, c E-10.1.
297 *Amendments to the Environmental Assessment Act*: *Support Saskatchewan's Growth Plan* (7 November 2012), online: Government of Saskatchewan <http://www.gov.sk.ca/news?newsId= 5e8ec3b9-0cb8-42c2-98f1-82f50d64d3c3>.
298 *Environmental Assessment Act*, *supra* note 293, s 7.6.
299 *Ibid*, ss 13-14.
300 *Ibid*, s 17.
301 *Ibid*, s 16.
302 RSQ, c Q-2 [*EQA*].

will range from $250 to $2,000 per day per person (individual) and $1,000-$10,000 per person (for a corporate entity or other legal person).[303]

With respect to penal sanctions, the *EQA* raises the penalties imposed on a person or municipality convicted of an offence under the *EQA*. For a legal person, penalties now range from $3,000 to $6,000,000 per day for a first offence, depending on the section of the *EQA* that is breached.[304]

The amendments make directors and officers of a legal person, partnership or association liable if the legal person, agent, or employee of the legal person commits an offence under the *EQA*, unless it can be established that the director or officer exercised due diligence and took all necessary precautions to prevent the offence.[305]

303 *Ibid*, ss 115.23-115.26.
304 *Ibid*, s 115.29-115.32.
305 *Ibid*, s 115.40.