RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO ENERGY LAWYERS

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This article provides an overview of recent regulatory and legislative developments of interest to energy lawyers. This includes the legal, political, and economic background to, and consequences of, new legislation and regulatory regimes. This also includes discussions of recent and ongoing judicial and regulatory decisions involving energy law. Topics discussed include market access, environmental and climate change regulation, Aboriginal consultation, and utilities regulation.

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I. INTRODUCTION

This has been a significant year for the practice of energy law in Canada given challenging market conditions, along with changes in government — federally and provincially in Alberta. The mandate and policy preferences of these new governments led to the introduction of new policies in 2015–2016, many of which are still in development and have contributed additional uncertainty to the energy industry during a time of unprecedented challenges.[1]

Many of these new policies are still being refined and the full impacts cannot yet be determined. On the oil and gas side, new technologies coupled with increased North American production has led to a reduced need for Canadian energy products in our traditional markets, underscoring the need for Canada to ensure access to new and diverse markets in a timely way. In Canada, major energy projects, notably pipelines and LNG export facilities, continue to languish in the regulatory processes and face new and

[1] Please note that the Canadian Energy Law Foundation does not necessarily endorse the views put forward in this article.

complicated challenges post-approval, thereby calling into question the timeliness or certainty of their completion.

With respect to electricity, the Government of Alberta has introduced an ambitious climate change strategy, including carbon pricing, along with a commitment to accelerate the retirement of Alberta's coal-fired generation and to replace two-thirds of coal-generated electricity with renewable sources of energy. This represents perhaps the most significant re-alignment of the industry since de-regulation.

This article is intended to canvass decisions of interest to energy lawyers as well as legislative and policy developments that have taken place since the last review. The article is organized into eight topics under relevant headings where the respective legislative and policy developments and judicial and administrative decisions are discussed with reference to the topical heading.

II. MARKET ACCESS AND PIPELINE MATTERS

A. FEDERAL

1. *PIPELINE SAFETY ACT*

The *Pipeline Safety Act* received Royal Assent on 18 June 2015 and came into force on 18 June 2016, subject to proclamation by the Governor in Council.[2] The *PSA* amended the *National Energy Board Act*[3] and the *Canada Oil and Gas Operations Act*.[4]

The Federal Government's backgrounder page to the legislation affirms Canada's commitment to world class pipeline safety, and states that through this act it is "implementing a suite of measures to strengthen incident prevention, preparedness and response, and liability and compensation."[5]

The legislation is intended to explicitly reinforce the "polluter pays" principle[6] and includes the unlimited liability of a pipeline operator for negligent spills, including liability to cover government costs incurred in relation to the event. The *PSA* also introduces limitations on liability for pipeline accidents without proof of fault or negligence. The *PSA* specifies that an operating pipeline company with a capacity of 250,000 barrels (in aggregate) or more per day is liable for up to $1 billion, or a greater amount as prescribed by regulation.[7]

In conjunction with this requirement, the *NEBA* will now include a provision requiring pipeline companies to maintain a readily accessible fund equal to the limit of liability

2 *Pipeline Safety Act*, SC 2015, c 21 [*PSA*].
3 *National Energy Board Act*, RSC 1985, c N-7 [*NEBA*].
4 *Canada Oil and Gas Operations Act*, RSC 1985, c O-7 [*COGOA*].
5 Natural Resources Canada, "Backgrounder: Pipeline Safety" (Ottawa: NRC, 18 June 2015), online: <news.gc.ca/web/article-en.do?nid=989119>.
6 *PSA*, *supra* note 2, Summary.
7 *Ibid*, s 48.12(5)(a).

established for its particular capacity.[8] The amendments established by the *PSA* are also intended to ensure that responsibility for abandonment costs remains with the pipeline company.

B. THE WEST

1. TRANS MOUNTAIN EXPANSION PROJECT

a. Federal Paramountcy and Pipelines: *Burnaby (City of) v. Trans Mountain Pipeline ULC*[9]

On 16 December 2013, Trans Mountain ULC (Trans Mountain) filed an application with the National Energy Board (NEB or the Board) seeking approval of the Trans Mountain Expansion Project (TM Project). The TM Project proposes to twin the existing Trans Mountain pipeline between Strathcona County, Alberta and Burnaby, British Columbia, and would increase the pipeline's capacity to approximately 890,000 barrels per day.[10]

The TM Project required a public hearing before the NEB. The hearings were acrimonious, with one of the most contentious issues being the extent and scope of Burnaby's (a municipality) powers to restrict or otherwise regulate a federal pipeline undertaking. This issue was first dealt with before the Board, although Burnaby subsequently advanced cases challenging the NEB's jurisdiction before the British Columbia Supreme Court and the Federal Court of Canada. The litigation focused on constitutional issues linked to Burnaby municipal bylaws and the resistance of the municipality to Trans Mountain's activities taking place on Burnaby Mountain in relation to investigating alternative routes for the pipeline.

Before the Board:

In Ruling No. 40, the NEB responded to Trans Mountain's notice of constitutional question which sought an order that Burnaby comply with section 73(a) of the *NEBA* by permitting access to investigation sites and refraining from obstructing Trans Mountain's ability to complete its necessary activities in the area.[11] The NEB considered both the applicability and operability of the impugned Burnaby park and traffic bylaws (Bylaws) and held there to be a clear operational conflict between the *NEBA* and the Bylaws, rendering the *NEBA* paramount to the extent of the conflict. Alternatively, the NEB found the doctrine of interjurisdictional immunity applied, leaving the Bylaws "inapplicable to the extent they impair temporary access to the Subject Lands by Trans Mountain for the purposes set out in paragraph 73(a)"[12] of the *NEBA*. As a result, the Board issued an order preventing Burnaby from using its bylaws to impede Trans Mountain's *NEBA*-authorized activities.[13]

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8 *Ibid*, s 48.13.
9 2015 BCSC 2140, [2016] 5 WWR 332 [*Burnaby*].
10 Trans Mountain, "Proposed Expansion," online: <https://www.transmountain.com/proposed-expansion>.
11 *Trans Mountain Notice of Motion and Notice of Constitutional Question* (23 October 2014), A4D6H0, online: NEB <https://docs.neb-one.gc.ca> [Ruling No 40].
12 *Ibid* at 15.
13 *Ibid* at 17–18.

Before the Courts:

In October 2014, Burnaby applied for leave to appeal to the Federal Court of Appeal on the grounds that the Board erred in law and jurisdiction in relation to Ruling No. 40. The Federal Court of Appeal denied leave, dismissing the application without reasons on 12 December 2014.

Burnaby then sought a declaration against the NEB from the British Columbia Supreme Court. In November 2015, Justice Macintosh rendered his decision in *Burnaby*.[14] Justice Macintosh determined that this was a "rare case" in which the Court should decline jurisdiction on a constitutional issue, as the NEB properly had jurisdiction over these questions and had rendered a decision.[15] As the British Columbia Supreme Court does not have jurisdiction to supervise the NEB, Justice Macintosh held it would be an "unworkable and likely chaotic" result if the Court reached the opposite conclusion of the NEB.[16] It was noted that Burnaby initiated its application only due to its failure at the NEB and Federal Court of Appeal, which was perceived to be an abuse of process.[17]

Notwithstanding the ruling as to jurisdiction, Justice Macintosh proceeded to answer the constitutional questions in the event a higher court ultimately determined he improperly declined jurisdiction. The test outlined by the Court was "whether the application of the provincial law precludes the practical operation of the federal undertaking in its core function."[18] The Court came to the same result as the NEB and concluded that the case engaged the federalism doctrines of paramountcy and interjurisdictional immunity, rendering provincial laws inoperative and inapplicable to the extent they interfere with the core of the NEB's jurisdiction over interprovincial pipelines — including the power to determine where pipelines are located.[19]

b. NEB Recommends Approval of the TM Project

On 19 May 2016, the NEB issued a 533-page report recommending that Cabinet approve the TM Project on the basis that the TM Project could be constructed, operated, and maintained in a safe manner.[20] In its environmental assessment, the NEB found that over 85 percent of the proposed route paralleled land already disturbed from the existing pipeline, and that risks were low so long as the required mitigation and safety measures were implemented.

The recommendation is subject to 157 conditions, which touch on everything from project engineering and safety to steps required for environmental protection. The conditions also stipulate ongoing consultation with potentially affected First Nations for the duration of construction and operations.

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14 *Burnaby*, *supra* note 9.
15 *Ibid* at para 41.
16 *Ibid* at para 44.
17 *Ibid* at para 49.
18 *Ibid* at para 68.
19 *Ibid* at paras 65, 84–85.
20 Canada, National Energy Board, *Trans Mountain Expanion Project*, A77045 (Calgary: NEB, May 2016), online: NEB <https://neb-one.gc.ca/fetch_e.asp?Id=A77045>.

The statutory review period of the TM Project under the *NEBA* was extended on account of the federal government's policy announcement to strengthen the NEB review process and include the assessment of upstream greenhouse gas (GHG) emissions.[21] The Minister of Natural Resources has also convened a ministerial panel to allow for further feedback and engagement with potentially affected communities and Indigenous groups on the TM Project route. The members of the panel include Kim Baird, a former Chief of the Tsawwassen First Nation, Annette Trimbee, the President and Vice-Chancellor of the University of Winnipeg, and Tony Penikett, a former Premier of Yukon. The panel will provide a report to the Minister in November 2016 with the final Cabinet decision on the TM Project expected in December 2016.

3. ENBRIDGE LINE 3 REPLACEMENT PROGRAM

On 5 November 2014, Enbridge Pipelines Inc (Enbridge) submitted an application to the NEB seeking approval of the Line 3 Replacement Program (Line 3 Project).[22] The Line 3 Project would include the decommissioning and replacement of its existing crude oil pipeline with a larger diameter pipeline, including an upgrade to remotely operated sectionalizing valves and additional tankage. The Line 3 Project is proposed to have two segments. The first segment is from the Hardisty Terminal in Alberta to the Cromer Terminal in Manitoba, and the second segment is from a tie-in point at NW 9-9-26 WPM to the Gretna Station in Manitoba.[23] The Line 3 Replacement Pipeline will ultimately replace the Existing Line 3 Pipeline, which has an average annual capacity of 127,190 m3/d (760,000 bbl/d).[24]
In its application to the NEB, Enbridge sought:

- A certificate of public convenience and necessity for the Line 3 Project under section 52 of the *NEBA*;

- A recommendation that under *Canadian Environmental Assessment Act*[25] the Line 3 Project is not likely to cause significant adverse effects;

- An order under section 58 of *NEBA* exempting the proposed new tanks, pump stations, and associated facilities from provisions of paragraphs 30(1)(b), 31(c), 31(d), and sections 33 and 47 of *NEBA*; and

- An order under section 45.1 of the *National Energy Board Onshore Pipeline Regulations* allowing Enbridge to decommission portions of the pipeline in accordance with the methodology set out in Enbridge's Application.

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21 This topic is discussed in greater detail in Part III, below.
22 *Enbridge Pipelines Inc – Line 3 Replacement Program*, A64152, A64166, A64156, A64179, A64180, A64187, online: NEB <https://docs.neb-one.gc.ca>.
23 *Ibid*.
24 *Ibid*.
25 *Canadian Environmental Assessment Act, 2012*, SC 2012, c 19 [*CEAA* 2012].

Decision of the Board:

On 25 April 2016, the NEB released its decision on the Line 3 Project, wherein it concluded: "that the Line 3 Replacement Program (Project) is in the overall Canadian public interest [and] with the implementation of mitigation measures, including the Board's conditions, the Project is not likely to cause significant adverse environmental effects."[26] The NEB's approval of the Line 3 Project includes a number of mandatory conditions Enbridge must meet.

With respect to environmental effects, the NEB recognized that the Line 3 Project will "avoid the need for ongoing maintenance and repairs to the Existing Line 3 Pipeline, some of which, such as integrity digs, are of a relatively high intensity."[27]

Regarding the decommissioning of the existing pipeline, the NEB viewed the fact that Enbridge negotiated comprehensive settlement agreements with the Canadian Association of Energy Pipeline Landowners Associations, the Manitoba Pipeline Landowners Association, and the Saskatchewan Association of Pipeline Landowners as positive. However, Enbridge is still required to make additional filings with the NEB before it begins decommissioning, including a detailed Final Decommissioning Plan, a Decommissioning Treatment Monitoring Program, and a Minimally-Invasive Procedure Evaluation Report.[28] Enbridge will also be required to notify the Board (and possibly obtain Board approval) if remedial or adaptive management measures are required after decommissioning. The NEB will not simply accept a plan regarding the final abandonment activities; rather it will require Enbridge to file an abandonment application in the future, once the remaining lifecycle steps can be carried out. Enbridge will also be required to report on the status of the pipeline corridor every five years.

The NEB's caution regarding decommissioning proposal was based on an inconclusive determination that the benefits of removing the existing Line 3 Pipeline outweigh the risks of leaving it in place. Accordingly, continued monitoring and reporting requirements will be imposed and more information about the decommissioning will be required. The Board indicated that this will be accomplished through continued engagement with stakeholders and by evaluating the decommissioning and abandonment proposals.

In terms of Aboriginal issues associated with the Line 3 Project, the Board imposed two conditions regarding future engagement with Aboriginal groups. The first requires Enbridge to file an ongoing consultation plan for Aboriginal groups going forward for the Board's approval. The second was for Enbridge to develop and file an Aboriginal Monitoring Plan for the construction phase of the Project, wherein the Panel "expects Enbridge to make efforts to accommodate active monitoring where desired by an Aboriginal group and where reasonable and safe, although observational site visits may be a component."[29] The Panel also noted that the Aboriginal Monitoring Plan would be more fulsome than this single

26 *Re Enbridge Pipelines Inc Volume 1: Our Decisions and Recommendations* (25 April 2016), A4Z5U2, online: NEB <https://docs.neb-one.gc.ca>.

27 *Ibid* at 4.

28 *Ibid* at 8.

29 *Ibid* at 11.

component. Enbridge must provide the NEB with an explanation as to why if it decides that it cannot reasonably accommodate such requests. The Panel further recommended for the NEB to consider the ultimate effectiveness of the Aboriginal Monitoring Plan to support continual improvement and so that the NEB, industry participants, and Aboriginal groups can work together to create principles, objectives, or a framework approach to refine the development of Aboriginal monitoring programs for large pipeline projects generally.

4. NORTH MONTNEY MAINLINE NATURAL GAS PIPELINE APPROVAL

NOVA Gas Transmission Ltd. (NOVA) filed an application with the NEB seeking approval of the North Montney Mainline Project (Montney Project) in November 2013.[30] The Montney Project involves the construction and operation of 301 kilometres of new pipeline and related facilities in northern Alberta's Peace River Regional District. It is intended to extend the NOVA system into the northeast British Columbia shale gas fairway and to support the integration of NOVA's system to proposed LNG projects.

The NEB issued a report in April 2015 recommending Federal Government approval of the Montney Project (NEB Report),[31] including 45 conditions that it believed should be applied to the Montney Project. These conditions arose from issues raised at the hearing, including: the need for the proposed project; the potential environmental, socio-economic, and commercial impacts; the suitability of the proposed route; the potential impact on Aboriginal interests; and the terms and conditions required for approval.[32] The NEB Report includes a strong dissent from panel member Shane Parrish, who held that NOVA had not provided sufficient evidence as to the routing options that would not cross through the Peace Moberly Tract.[33]

Although the construction of the pipeline was approved, the Board rejected NOVA's application for a rolled in tolling methodology that would have spread the cost of the Line 3 Project to all users of the NOVA system. Instead, the Board ruled that NOVA was authorized to use a rolled in toll calculation method only until deliveries commenced to the Prince Rupert Gas Transmission Pipeline. Upon the commencement of exports, NOVA will be required to either apply stand alone tolls for the North Montney Pipeline or develop a new tolling regime that better satisfies the principle of cost-causation and the goal of economic efficiency when applied to expansion projects such as this. This unique condition was the result of the Board failing to find sufficient integration of the North Montney Pipeline to the rest of the NOVA system once the Prince Rupert Gas Transmission Project became operational, at which point the service provided would more appropriately be characterized as point to point.[34]

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30 NOVA Gas Transmission Ltd: North Montney Project Application, A55184, online: NEB <https://docs.neb-one.gc.ca>; NOVA Gas Transmission Ltd – North Montney Project Application, A55183, online: NEB <https://docs.neb-one.gc.ca>; NOVA Gas Transmission Ltd – North Montney Project Application, A55180, online: NEB <https://docs.neb-one.gc.ca>.

31 *Re NOVA Gas Transmission Ltd* (15 April 2015), A69520, online: NEB <https://docs.neb-one.gc>.

32 *Ibid* at 160.

33 *Ibid* at 104.

34 *Ibid* at 30.

On 10 June 2015, the Federal Minister of Natural Resources announced the Federal Government had accepted the NEB's recommendation of approval with conditions.[35] Before NOVA can begin construction on the pipeline it must establish the steps it will take to meet the subject terms and conditions of approval.

The Montney Project was subject to two Federal Court of Appeal applications for judicial review by First Nations applicants.[36] Both applications involved issues regarding the Crown's duty to consult and accommodate. The Federal Court of Appeal dismissed both applications for judicial review on 12 August 2015.[37] The Saulteau First Nations applied to the Supreme Court of Canada for leave to appeal the Federal Court of Appeal's dismissal on 13 October 2015. As of the time of writing, the Supreme Court has not yet issued a decision.[38]

Following the recent decision of the British Columbia Supreme Court in the *Coastal First Nations* case,[39] the Montney Project is now also subject to review by the British Columbia Environmental Assessment Office, in particular First Nations consultation. NOVA has also applied to the NEB for a one year extension to the sunset provisions of the certificate and order. The Saulteau and West Moberly First Nations also asked the NEB to consider attaching additional consultation requirements to any extension in respect of routing choices through areas they have identified as critical to their Treaty 8 rights. The NEB has extended the date on which to comment on the sunset provision request from NOVA to 31 December 2016.[40]

5. NEB APPROVES ALLIANCE NEW SERVICES TARIFF APPLICATION

The Canadian segment of the Alliance pipeline runs from southeast Saskatchewan to Fort St. John, British Columbia. On 9 July 2015, the NEB approved Alliance Pipeline Limited's (Alliance) New Services and Related Tolls and Tariffs application (New Service Application)[41] following a 14 month process of review and public hearings. The New Service Application involves a change in Alliance's business model that will move away from long-term firm service contracts due to changes in market expectations.[42] Alliance sought the following from the Board:

- Approving the New Service Offering tolls and tariffs;

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35 Natural Resources Canada, "Government of Canada Accepts Recommendation to Approve Natural Gas Pipeline Proposal" (Ottawa: NRC, 10 June 2015), online: <news.gc.ca/web/article-en.do?nid=986479>.

36 *NOVA Gas Transmission Ltd Application dated 8 November 2013 for the North Montney Mainline Project* (April 2015), A69520, online: NEB <https://docs.neb-one.gc.ca>, leave to appeal to FCA refused, 15-A-36 to 15-A-37 (12 August 2015), leave to appeal to SCC requested, online: <www.scc-csc.ca/case-dossier/info/dock-regi-eng.aspx?cas=36677> [*Saulteau First Nations* Docket].

37 Canada, National Energy Board, "Court Challenges to National Energy Board or Governor in Council Decisions" (Ottawa: Government of Canada) (29 September 2016), online: <https://www.neb-one.gc.ca/pplctnflng/crt/index-eng.html>.

38 See *Saulteau First Nations* Docket, *supra* note 36.

39 *Coastal First Nations v British Columbia (Minister of Environment)*, 2016 BCSC 34, 85 BCLR (5th) 360 [*Coastal First Nations*]. See discussion in Part IV, below.

40 *NOVA Gas Transmission Ltd (NGTL) North Montney Project Request for Extension of Sunset Clause under Section 21 of the National Energy Board Act (NEB Act)* (16 May 2016), A4Z9Z7, online: NEB <https://docs.neb-one.gc.ca>.

41 *Alliance Pipeline Ltd as General Partner of Alliance Pipeline Limited Partnership* (9 July 2015), A71142, online: NEB <https://docs.neb-one.gc.ca> [*Alliance* Reasons for Decision].

42 *Ibid* at viii.

- Approving the mechanism for, and calculation of, the Recoverable Variances Demand Surcharge and Commodity Surcharge and the Pipeline Abandonment Demand Surcharge and Commodity Surcharge;

- Approving a streamlined regulatory process for new services and new or revised tolling proposals;

- Converting the existing agreements for transportation service to continue under the New Services Offering;

- Providing for continued relief from the requirement to file with the Board Quarterly Surveillance Reports and Performance Measures; and

- Granting such further and other relief as Alliance may request or the Board may consider appropriate.[43]

The Board approved the New Service Application subject to 14 conditions.[44] The NEB found that the resultant flexibility for shippers and the apparent attractiveness of the new structure supports a finding of reasonableness and the firm tolls to be reasonable and not unjustly discriminatory. The Recoverable Cost Variances methodology was found to be appropriate for recovery of costs difficult to forecast.

The NEB approved the use of bids for both seasonal and interruptible services but imposed limits on bid floors based on a percentage of corresponding fixed five-year firm service tolls. Further, Alliance will be required to maintain a reserve account and to apply for approval prior to distributions to equity holders.[45] The NEB rejected Alliance's application for exemption from Quarterly Surveillance Reports as reporting is essential to monitoring Alliance's performance. Alliance implemented the New Service offering tolls and tariffs as of 1 December 2015.

6. PRINCE RUPERT GAS TRANSMISSION PROJECT

The Prince Rupert Gas Transmission Project (PRGT Project) is a proposed, roughly 900-kilometre, natural gas pipeline located wholly within British Columbia, extending from near Hudson's Hope, where it would connect to the NOVA Gas Transmission Ltd. System (NGTL System), to the proposed Pacific Northwest LNG facility on Lelu Island, near Prince Rupert.

On 18 February 2016, the Federal Court of Appeal granted leave to appeal pertaining to a decision of the NEB (*Michael Sawyer v. TransCanada Ltd. and Prince Rupert Gas*

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43 *Alliance Pipeline Ltd New Services and Related Tolls and Tariffs* (20 August 2014), A4A2X6, online: NEB <https://docs.neb-one.gc.ca>.
44 *Alliance* Reasons for Decision, *supra* note 41, Appendix II.
45 *Ibid* at x.

Transmission Ltd.),[46] wherein the Board denied an application by Mr. Sawyer seeking a declaration that the PRGT Project fell within federal jurisdiction.

In his application to the NEB dated 9 October 2015, Mr. Sawyer requested the NEB issue a declaratory order that the PRGT Project is properly within federal jurisdiction, issue a Notice of Constitutional Question pursuant to section 57 of the *Federal Courts Act*,[47] and in the alternative refer the question of jurisdiction to the Federal Court of Appeal. The Federal Court of Appeal has yet to make a decision in this matter and the appeal process is ongoing.

Mr. Sawyer relied on the Supreme Court of Canada decision in *Westcoast Energy Inc. v. Canada (National Energy Board)*[48] for the principle that an intraprovincial pipeline falls into federal jurisdiction if it either forms a part of, or is integral to, a federal work or undertaking. Mr. Sawyer's submission was that the PGRT Project and its connection to the NGTL System, comprises a single federal undertaking.

In its 30 November 2015 decision, the NEB determined that the PRGT Project is not a federal undertaking such that it should be subject to regulation under the *NEBA*.[49] While the NEB recognized that there is a relationship between the PRGT Project and the NGTL System, this relationship is not sufficient to establish that the PRGT Project is prima facie within federal jurisdiction. In dismissing Mr. Sawyer's application, the NEB emphasized that the PRGT Project is wholly located in the province of British Columbia and that the character and function of the PRGT Project is local in nature.

C. THE EAST

1. QUEBEC FIRST NATIONS CHALLENGE CHALEUR TERMINALS OIL EXPORT TERMINAL

As pipelines continue to face political and legal challenges, crude by rail continues to play an important role in meeting the transportation needs of crude oil producers, including new market access. Chaleur Terminals Inc. (CTI), a subsidiary of Secure Energy Services Inc., acquired 250 acres in the Port of Belledune, New Brunswick to construct a terminal for the purpose of exporting oil transported east from Alberta via rail. Once constructed, the project would result in approximately 220 rail cars travelling to the Port of Belledune daily.

In July 2015, the Listuguj Mi'gmaq First Nation (LMFN) applied to the New Brunswick Court of Queen's Bench seeking an order quashing the Approval to Construct Permit, the Environmental Approval Permit, and the Site Approval issued by the New Brunswick Minister of Environment in April 2015. The LMFN brought its application against both the Province of New Brunswick and CTI. The LMFN also sought a declaration that the Province breached its duty to consult and accommodate and that the Province remains subject to an

46 *Application of Michael Sawyer Regarding Jurisdiction Over the Proposed Prince Rupert Gas Transmission Project* (30 November 2015), A74353, online: NEB <https://docs.neb-one.gc.ca>, leave to appeal to FCA granted (18 February 2016).
47 *Federal Courts Act*, RSC 1985, c F-7.
48 [1998] 1 SCR 322.
49 *Application of Michael Sawyer Regarding Jurisdiction Over the Proposed Prince Rupert Gas Transmission Project* (30 November 2015), A74353, online: NEB <https://docs.neb-one.gc.ca>.

ongoing duty to achieve a reasonable accommodation with the LMFN. If granted, the LMFN's order would restrict the Province from issuing any further permits or approvals to CTI until it has fulfilled its obligations to LMFN.

The case is noteworthy as the applicant LMFN is situated in Quebec, whereas the terminal and its operations would be located in New Brunswick. The case highlights the ongoing challenges facing project developers seeking approval of projects designed to transport hydrocarbons and how the Crown's duty to consult First Nations and Aboriginal Peoples in respect of such projects remains a powerful tool available to First Nations dissatisfied with a project approval. The application was heard on 16 March 2016 and the presiding Justice has indicated that a written decision will be issued in due course.

2. ONGOING CHALLENGES TO ENERGY EAST PIPELINE PROJECT

The Energy East Pipeline, a project proposed by TransCanada Pipelines Limited (TCPL) has recently faced a number of court challenges. The project is a 4,500 kilometre pipeline that will carry 1.1 million barrels of crude oil a day from Alberta and Saskatchewan to refineries in Quebec and New Brunswick and a marine terminal in New Brunswick.[50]

One of these challenges was brought by the Centre Quebecois du Droit de l'Environnement (CQDE).[51] The CQDE's application was for an interlocutory injunction to extend any deadlines for participating in the NEB's consideration of TCPL's application. CQDE was requesting an injunction until the Commissioner for Official Languages ruled on CQDE's request that the NEB provide a full translation of the Energy East Application.[52]

On 16 February 2015, the Federal Court rejected this application finding that it did not raise a serious question CQDE failed to demonstrate that they would suffer irreparable harm if an injunction was not granted, and therefore the balance of convenience favoured proceeding with the NEB's process.[53] Justice de Montigny also rejected CQDE's application on jurisdictional grounds finding that the Federal Court Trial Division did not have appellate or judicial review discretion over the NEB.[54]

On 1 March 2016, the Quebec Government filed an injunction application against TCPL asserting that the Quebec portion of the project should also be reviewed by the Bureau d'Audiences Publiques sur l'Environnement (BAPE) to allow Quebec's environmental agency to assess the environmental impacts within Quebec under the *Environment Quality Act*.[55] This injunction application was halted on 4 March 2016 when TransCanada agreed to submit to an environmental impact study conducted by the BAPE.[56]

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50 Canada, National Energy Board, "Energy East and Eastern Mainline Projects" (Ottawa: NEB, 3 October 2016), online: <https://www.neb-one.gc.ca/pplctnflng/mjrpp/nrgyst/index-eng.html>.

51 *Quebec Environmental Law Centre v National Energy Board et al*, 2015 FC 192, 476 FTR 8.

52 *Ibid* at paras 5–7.

53 *Ibid* at paras 28–30.

54 *Ibid* at para 17.

55 *Regulation Respecting a Cap-and-Trade System for Greenhouse Gas Emission Allowances*, CQLR c Q-2, r 46.1 [*GHG Regulations*].

56 Jonathan Montpetit, "TransCanada Backs Down, Will Submit Pipeline Impact Study to Quebec," *CBC News* (22 April 2016), online: <www.cbc.ca/news/canada/montreal/transcanada-backs-down-to-submit-pipeline-impact-study-to-quebec-1.3549283>.

The Mohawk Council of Kanesatake, among others, strongly oppose the project and have threatened to stop it. To date, members of the Mohawk First Nations have protested the project and have threatened to do whatever it takes to block the pipeline.[57]

Last, the statutory review period for the project pursuant to the *NEBA* has been extended on account of the Federal Government's policy announcement regarding the strengthening of the NEB review process and to include an assessment of upstream GHG emissions. This issue is discussed in greater detail in Part III, below.

D. UNITED STATES

1. REJECTION OF KEYSTONE XL, THE *NAFTA* CHALLENGE, AND A CIVIL SUIT

TCPL applied to the US State Department for a permit approving the Keystone XL Pipeline Project (Keystone XL) in September 2008. After more than seven years of review and the State Department's conclusion that, on a global scale, emissions are not likely to change as a result of the pipeline, President Obama announced his rejection of Keystone XL in November 2015.[58] The President stated that the pipeline project "will not serve the national interests of the United States."

In response, TCPL filed a Notice of Intent to submit a claim for arbitration under Chapter 11 of the *North American Free Trade Agreement*[59] on 6 January 2016 asserting that the rejection through the denial of a Presidential Permit was arbitrary and unjustified. The claim is grounded in the fact that TCPL was denied a permit, notwithstanding that "the Administration had concluded on six occasions that the pipeline would not have a significant impact on climate change."[60] TCPL argues its continued investment in the project was based on a reasonable expectation that the Administration would apply a fair process, consistent with past projects transferring the same product from the same locations.[61] In effect, TCPL is challenging the basis of the denial, which it argues was explicitly due to concerns about *perceptions* of leadership internationally, as opposed to the facts presented by the State Department. The damages claimed in the NAFTA arbitration are in excess of US$15 billion. TCPL also filed a civil action suit in the US District Court for the Southern District of Texas in January 2016 against certain US Government officials — John Kerry (Secretary of State), Loretta Lynch (Attorney General), Jeh Charles Johnson (Secretary of Department of

57 Philip Authier, "Mohawks Threaten to Block Energy East Pipeline, Saying Project is Threat to Way of Life," *National Post* (14 March 2016), online: <news.nationalpost.com/news/canada/mohawks-threaten-to-block-energy-east-pipeline-saying-project-is-threat-to-way-of-life>.

58 The Associated Press, "Barack Obama Rejects Keystone XL Pipeline Citing 'National Interest,'" *CBC News* (6 November 2015), online: <www.cbc.ca/news/business/keystone-xl-pipeline-obama-1.3307440>.

59 *North American Free Trade Agreement Between the Government of Canada, the Government of Mexico and the Government of the United States*, 17 December 1992, Can TS 1992, TS 1994 No 2 (entered into force 1 January 1994) [*NAFTA*].

60 TransCanada, "Notice of Intent to Submit a Claim to Arbitration Under Chapter 11 of the North American Free Trade Agreement" (6 January 2016) at para 1, online: <www.keystone-xl.com/wp-content/uploads/2016/01/TransCanada-Notice-of-Intent-January-6-2016.pdf>.

61 *Ibid* at para 2.

Homeland Security), and Sally Jewell (Secretary of Department of Interior).[62] The complaint is a constitutional challenge questioning the legitimacy of the President's "unilateral power, unsupported by any statute and contrary to the expressed wishes of Congress" to reject Keystone XL.[63] TCPL asserts that the President's decision to deny a Presidential Permit was incompatible with Congress' express powers under the Constitution to regulate commerce with foreign nations.[64] The complaint cites the unprecedented nature of President Obama's use of unilateral power to prohibit construction in light of the previous limited authority of past Presidents in similar circumstances.[65] Ultimately, TCPL is seeking declarations that the defendants were not legally authorized to prohibit the construction and operation of Keystone XL, and the decision is without lawful effect.

The US Government filed a motion to dismiss the civil action on 1 April 2016 with TransCanada filing a brief in opposition in early May 2016. Most recently, on 9 May 2016, the US Chamber of Commerce[66] along with the states of Oklahoma, Kansas, Montana, Nebraska, South Dakota, and Texas filed amicus briefs supporting TCPL.[67] The existing Keystone pipeline with the Keystone XL addition would run through each of these states.

2. DECISION TO END THE US OIL EXPORT BAN

While rejecting the Keystone XL Project on environmental grounds, the United States Government lifted the American oil export ban, paving the way for future exports of American oil. In December 2015, President Obama executed the *Offshore Production and Energizing National Security Act*[68] controversially approved by Congress, lifting the long-time ban on exporting American oil. Section 501 of the *OPENS Act* provides that "any domestic crude oil or condensate (other than crude oil stored in the Strategic Petroleum Reserve) may be exported without a federal license to countries not subject to, but subject to export licensing requirements or other restrictions in the event of a national emergency or national security sanctions by the United States."[69]

The lifting of the oil export ban, coupled with the rejection of Keystone XL by President Obama, underlines the importance of Canadian producers securing alternative markets for growing Canadian production in light of changing oil markets and in particular growth in US crude production.

The United States (previously the primary market for Canadian natural gas exports) is now competing with Canada in the global LNG race, with a number of American LNG

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62 *TransCanada Keystone Pipeline LP et al v Kerry et al* (6 January 2016), Southern District of Texas 4:16-CV-00036 (SD Tex 2016) [*Keystone*] (Constitutional Filing, Plaintiff at paras 10–13, online: <www.keystone-xl.com/wp-content/uploads/2016/01/TransCanada-Complaint-January-6-2016.pdf>).

63 *Ibid* at para 1.

64 *Ibid* at para 72.

65 *Ibid* at paras 93–94.

66 *Keystone*, *supra* note 62 (Amicus Brief of the Chamber of Commerce of the United States and the National Association of Manufacturers, online: <www.chamberlitigation.com/content/transcanada-keystone-pipeline-lp-v-kerry-et-al>).

67 *Keystone*, *ibid* (Amicus Brief of the States of Oklahoma, Kansas, Montana, Nebraska, South Dakota, and Texas, online: <https://www.ok.gov/oag/documents/Amicus of OK, KS, MT, NE, SD, and TX.pdf>).

68 US, Bill S 2011, *Offshore Production and Energizing National Security Act*, 114th Cong, 2015-2016 [*OPENS Act*].

69 *Ibid*, s 501(a).

development projects seeking final approval and the first LNG cargoes having already been delivered by Cheniere Energy's Sabine Pass Facility.

III. CLIMATE CHANGE AND GHG EMISSIONS

Across Canada there has been a renewed focus on climate change and reducing GHG emissions on both the provincial and federal levels. The newly elected federal government has taken an active role in environmental climate change discussions on the global stage, and in particular had a significant presence at the Paris Climate Change Conference in December. The newly elected provincial government of Alberta has also framed its platforms and public persona on having a definitive climate change plan for the province.

A. ALBERTA'S CLIMATE LEADERSHIP PLAN

On 22 November 2015, the Government of Alberta released its Climate Leadership Plan (Plan)[70] based on the "Climate Leadership: Report to the Minister" (Report to the Minister), which was authored by a Climate Change Advisory Panel (Panel).[71] When announced, the Plan emphasized the province's commitment to eliminating coal fired generation and limiting GHG emissions in the province. The Government's apparent intention is to demonstrate that Alberta is committed to climate change and managing GHG emissions, while also ensuring that Alberta's energy producers obtain greater market access. At this stage it is unclear which aspects of the Report to the Minister will eventually become policies, aside from those announced as part of the Plan on 22 November 2015.

1. SUMMARY OF THE CLIMATE LEADERSHIP REPORT

The Panel's suggestions centred around five main components:

1. The replacement of the *Specified Gas Emitters Regulation*[72] with a broader carbon price policy that applies to all end-use carbon emissions;

2. The phase out of all coal electricity production by 2030, and the replacement of two thirds of current coal-generated electricity with renewable production, which will represent 30 percent of electricity generated in the province;

3. Significant methane reductions;

4. A 100Mt cap on oil sands emissions; and

70 Government of Alberta, Press Release, "Climate Leadership Plan Will Protect Albertans' Health, Environment and Economy" (22 November 2015), online: <www.alberta.ca/release.cfm?xID=38885E74F7B63-A62D-D1D2-E7BCF6A98D616C09> ["Climate Leadership Plan"].

71 Alberta, Climate Change Advisory Panel, *Climate Leadership: Report to Minister* (Edmonton: Government of Alberta, 20 November 2015), online: <www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf> [*Report to the Minister*].

72 *Specified Gas Emitters Regulation*, Alta Reg 139/2007 [*SGER*].

5. Investment in creating energy efficient and energy resilient communities, and energy innovation and technology.[73]

The Plan, as announced, has not adopted all of these suggestions. Instead, the Alberta government's current Plan focuses on ending coal pollution, establishing a carbon pricing scheme, capping oil sands emissions, and reducing methane emissions.[74] The summary below is primarily based on the Plan as informed by the Report to the Minister.

In the 8 March 2016 throne speech the Government of Alberta announced it will implement the Plan through the *Climate Leadership Implementation Act*.[75]

2. THE CARBON PRICE

The backbone of the Plan is the carbon levy, which is effectively a flat fee for carbon emissions for transportation and heating fuels. The proposed carbon price will eventually replace the current regime under the *SGER*. According to the Plan, it is expected that the carbon price will cost Albertan families \$191 in 2017, with maximum rebates of \$200.[76] Sixty percent of Albertan households will be eligible for the full rebate.[77] The money generated from the carbon price is expected to be invested in the Alberta economy. In particular, the Alberta government has predicted that over the next five years the carbon levy is projected to collect \$9.6 billion.[78] The Government has stated that \$6.2 billion will be spent on diversifying our energy economy and creating jobs, while another \$3.4 billion will provide support for households, businesses, and communities adjusting to the carbon price.[79]

Operationally, large emitters will be allocated emissions rights in proportion to their output or value added, while end-use emitters will have to acquire permits for their emissions either by purchasing credits or by paying carbon levies. This type of carbon pricing scheme is expected to incentivize companies to reduce emissions without removing their ability to be competitive.

It should also be noted that the *SGER* was renewed for a period of two years in June 2015.[80] Originally the *SGER* was introduced in 2007 and was set to expire in September 2014.[81] It was extended by the former provincial government until 30 June 2015 and then by the current government until the end of 2017. The renewal of the *SGER* increased the carbon levy from \$15/tCO_2e to \$20 in 2016 and \$30 in 2017.[82] The Alberta government's renewal

73 "Climate Leadership Plan," *supra* note 70.
74 *Ibid*.
75 Alberta, Legislative Assembly, *Speech from the Throne*, 29th Leg, 2nd Sess (8 March 2016), online: <www.alberta.ca/throne-speech.cfm>.
76 Government of Alberta, "Climate Leadership: Carbon Levy and Rebates," online: <www.alberta.ca/climate-carbon-pricing.cfm> ["Carbon Levy and Rebates"].
77 *Ibid*.
78 *Ibid*.
79 *Ibid*.
80 Government of Alberta, News Release, "Alberta's Climate Change Regulations Extended" (19 December 2014), online: <www.alberta.ca/release.cfm?xID=37535EC25331A-C352-D068-3F2567BFFF6F3506>.
81 *Ibid*.
82 *Report to the Minister*, *supra* note 71 at 37.

also announced that the intensity reduction requirements under the legislation would increase to 15 percent on 1 January 2016, and 20 percent by 1 January 2017.[83]

3. PHASE OUT OF COAL-FIRED ELECTRICITY

Another major component of the Plan is the accelerated phase out of coal-fired electricity. While current federal regulations already mandated that 75 percent of Alberta's coal-fired units would be phased out by 2030,[84] the Report called for the complete phase out of all coal-fired electricity in the same timeline. The Alberta government's current plan is for there to be no pollution from coal-fired electricity generation by 2030, and to replace two-thirds of this generation with renewable energy production, with natural gas generated electricity making up the remaining third.[85]

Cognizant that this is an ambitious goal, the Province has stated it will increase subsidization for renewable energy producers.[86] Further, the Report to the Minister proposes the adoption of a clean power call mechanism, which is effectively a competitive bidding system between renewable energy companies for governmental support. The Report also proposes to provide financial assistance to communities that will be affected, especially the communities that have relatively new coal-fired power generation plants.[87]

On 16 March 2016, the Alberta government announced that Terry Boston will be the main facilitator of the Coal Retirement Plan.[88] Terry Boston was formerly the CEO of North America's largest power grid, PJM Interconnection. In this role, Mr. Boston is meant to provide the provincial government with options that will ensure the reliability and stability of the Alberta energy grid. With the main expectation that Mr. Boston will primarily be addressing the six coal-fired generators that were otherwise expected to operate past 2030.

4. METHANE REDUCTIONS

One of the other major items the Plan targets is methane production. Methane has been targeted both because Alberta is a significant methane emitter and because it is one of the most cost-effective ways of reducing GHG emissions in Alberta.[89]

The Plan aims to reduce methane using a mixed regulatory and market-based approach. The current proposal to reduce methane emissions will use two approaches. First, new emissions design standards will be applied to new Alberta facilities, and secondly the government will develop a five year voluntary Joint Initiative on Methane Reduction and Verification.[90] While it is unclear if these specific suggestions will be adopted, the

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83 "Carbon Levy and Rebates," *supra* note 76.
84 *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*, SOR/2012-167.
85 "Climate Leadership Plan," *supra* note 70.
86 *Ibid.*
87 *Ibid.*
88 Government of Alberta, News Release, "Alberta Takes Next Steps to Phase-Out Coal Pollution Under Climate Leadership Plan" (16 March 2016), online: <www.alberta.ca/release.cfm?xID=40400064C4850-E326-56B9-4ED21CDD882F3960>.
89 Government of Alberta, "Reducing Methane Emissions," online: <www.alberta.ca/climate-methane-emissions.cfm>.
90 *Ibid.*

government's policy announcement states that "Alberta's reduction target and timeline match the commitments recently announced by the Canadian and American federal governments."[91] The Provincial Government plans to reduce methane emissions to 45 percent of 2014 levels by 2025.[92]

5. CAP ON OIL SANDS EMISSIONS

The Plan includes the imposition of a 100 million tonne cap on oil sands emissions.[93] At the time the Plan was announced, the oil sands generated approximately 70 million tonnes of emissions per year. The proposed cap is hoped to encourage oil sands producers to improve performance and become as efficient as conventional oil producers, while providing room for future growth in the industry.

6. ENERGY INVESTMENTS AND SUPPORTS

In addition to plans to reduce emissions, the Panel suggested that the Province work with communities and renewable energy producers to, *inter alia*, develop ways existing facilities could operate in a more energy efficient manner. This section of the Report to the Minister suggests amending building regulations to require more energy efficient development, requiring communities to consider energy efficiency when making planning decisions, and calls for the involvement and consultation with Aboriginal people. In particular, Aboriginal people should be included when considering energy efficient initiatives and developing of renewable energy opportunities.[94] However, at this stage the Province has not included these suggestions from the Report to the Minister in the Plan.

The Report anticipated that the money generated from the carbon price would be used to support these types of energy investments, innovations, and supports. Overall, the Plan is ambitious and unique when compared to similar policies in other provinces. At this early stage it remains to be seen how these policies will be implemented and whether they will be effective.

7. AESO LED RENEWABLE ELECTRICITY PROGRAM

In one of its first acts under the Plan, on 26 January 2016, the government requested that the Alberta Electric System Operator (AESO) develop and implement a renewable electricity incentive program to assist in adding renewable generation capacity to the electricity grid in Alberta.

The AESO released an update on the stakeholder engagement process on 5 May 2016 wherein it provided a few details it expects will inform the renewable electricity program including that the definition of renewable will align with the definition used by Natural

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91 *Ibid*.
92 *Ibid*.
93 "Climate Leadership Plan," *supra* note 70.
94 *Ibid*.

Resources Canada and that the facilities may be expected to be in service in 2019.[95] The AESO provided the Alberta government with its draft recommendations in late May 2016.[96] The AESO also indicated that it expects to launch the first renewable energy program competition in the last quarter of 2016.

B. CARBON PRICING IN CANADA

The year 2015 saw several provinces adopt or move towards various carbon pricing schemes. Carbon pricing attempts to capture the external costs of carbon emissions. There are essentially two main ways to price carbon, through an Emissions Trading System (ETS) or through a carbon tax. An ETS system works by providing market incentives to participants who reduce emissions, while a carbon tax system puts a price on the actual carbon emissions at certain levels. Both schemes can be seen in Canada.

1. BRITISH COLUMBIA

British Columbia has utilized a carbon tax scheme based on a cap-and-trade system since 2008. On 12 May 2015, the Government of British Columbia called together a "Climate Leadership Team" to provide further recommendations to the province on a Climate Leadership Plan.[97] The Climate Leadership Team came up with 32 recommendations that canvass a number of different ways to reduce GHGs.[98] These recommendations include lowering the provincial sales tax from 7 percent to 6 percent and incrementally increasing the carbon tax, setting a legislated target of 33 percent GHG reduction from 2007 levels by 2030, and reaffirming a commitment to an 80 percent reduction from 2007 levels by 2050.[99] The Climate Leadership Team has also suggested that British Columbia develop a low-carbon transportation strategy, and make amendments to the *Clean Energy Act* to increase the integrated grid target from 93 percent to 100 percent by 2025.[100]

2. ALBERTA

As explained above, Alberta has chosen to adopt a carbon pricing scheme that places a price of $20 per tonne on carbon emissions starting in 2017, with the price of carbon increasing to $30 a tonne on 1 January 2018.[101]

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95 Alberta Electric System Operator, "Renewable Electricity Program Update to Stakeholders" (5 May 2016), online: <www.aeso.ca/assets/Uploads/Combined-REP-next-steps-and-questionnaire-summary.pdf>.

96 Alberta Electric System Operator, "Renewable Electricity Program," online: <www.aeso.ca/market/renewable-energy-program>.

97 British Columbia, Office of the Premier, News Release, "B.C. Names Climate Leadership Team" (12 May 2015), online: <https://news.gov.bc.ca/stories/bc-names-climate-leadership-team>.

98 British Columbia, Climate Leadership Team, *Recommendations to Government* (Victoria: Ministry of Environment, 2015), online: <engage.gov.bc.ca/climateleadership/files/2015/11/CLT-recommendations-to-government_Final.pdf>.

99 *Ibid* at 8.

100 *Ibid* at 13.

101 "Carbon Levy and Rebates," *supra* note 76.

3. MANITOBA

Manitoba has committed to implementing a cap-and-trade carbon pricing scheme in the province's climate change plan titled *Manitoba's Climate Change and Green Economy Action Plan*.[102] The plan was released in December 2015, and proposes to set emissions targets, establish a Demand Side Management entity to oversee provincial energy efficiency, to reduce emissions from government operations, and to work towards a shift towards a low-carbon economy.[103]

While the details of Manitoba's cap-and-trade system are still being worked out, Manitoba executed a Memorandum of Understanding with Ontario and Quebec on 7 December 2015 in an attempt to link the cap-and-trade systems used in each province.[104]

4. ONTARIO

a. Bill 172: *Climate Change Mitigation and Low-Carbon Economy Act, 2016*[105]

Much like the other provinces, Ontario has been actively updating its climate change strategy, including releasing both a draft regulation for its cap-and-trade program and a Climate Change Strategy. The cap-and-trade system is outlined in Bill 172, which received Royal Assent on 18 May 2016.

Under Bill 172, Ontario proposes to join the Western Climate Initiative (WCI) linking its cap-and-trade program with Quebec and California.[106] This type of system utilizes an auction floor price for carbon. Ontario is proposing to set its cap based on the best estimate of emissions that year.[107] All revenues generated under this cap-and-trade strategy are to be directed towards a Greenhouse Gas Reduction Account to fund green projects.

Further, under the currently proposed strategy Ontario will establish targets for the reduction of carbon emissions that will require regulated emitters to either take action or participate in the trading market to reduce their emissions. The objective is for Ontario to begin using this cap-and-trade system in 2017.[108]

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102 Government of Manitoba, *Manitoba's Climate Change and Green Economy Action Plan* (Winnipeg: Government of Manitoba, December 2015), online: <https://www.gov.mb.ca/conservation/climate/pdf/mb-climate-change-green-economy-action-plan.pdf>.

103 *Ibid* at 2.

104 Ontario, Office of the Premier, News Release, "Ontario, Québec and Manitoba Form a Dynamic Alliance to Fight Climate Change" (7 December 2015), online: <https://news.ontario.ca/opo/en/2015/12/ontario-quebec-and-manitoba-form-a-dynamic-alliance-to-fight-climate-change.html>.

105 Bill 172, *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, 1st Sess, 41st Leg, Ontario, 2016 [Bill 172].

106 Government of Ontario, *Ontario's Climate Change Strategy* (Toronto: Ministry of the Environment and Climate Change, 2015) at 10, online: <https://dr6j45jk9xcmk.cloudfront.net/documents/4928/climate-change-strategy-en.pdf>.

107 *Ibid* at 11.

108 *Ibid*.

In addition to introducing a cap-and-trade system, Bill 172 also proposes to take a more strategic approach to climate change. Explicitly included as part of the strategic approach under Bill 172 is the:

- Development of a long-term framework for climate action in Ontario;

- Involvement of climate change mitigation considerations into government decision-making and planning decisions; and

- Investment towards creating a carbon neutral public sector.[109]

Bill 172 also requires the Provincial Government to review its progress every five years, report to the public, and sets long-term emissions goals of reducing GHG emissions by 15 percent below 1990 levels by 2020 and 37 percent below 1990 levels by 2030.[110] It is expected that the first five-year plan under this strategy will be released in the spring of 2016.[111]

b. Bill 135: *Energy Statute Law Amendment Act, 2016*

Bill 135 received Royal Assent on 9 June 2016. Bill 135 proposes to amend the *Electricity Act, 1998*, the *Green Energy Act, 2009*, and the *Ontario Energy Board Act, 1998*.[112] The amendments focus on four main areas:

1. The requirement, under the *Electricity Act, 1998*, that the Minister of Energy develop and implement long-term energy strategies. These strategies should be based on technical reports concerning the adequacy and reliability of electricity resources and supply as provided by the Independent Electricity System Operator (IESO).

2. The authority to develop these long-term strategies will also carry with it the authority to issue directives to the IESO and the Ontario Energy Board (OEB) regarding procurement. This will mean that the IESO is authorized to enter contracts on its own for electricity supply, capacity, storage, transmission, and conservation projects.

3. The current Feed-in-Tariff (FIT) program, as set out in section 25.35 of the *Electricity Act, 1998*,[113] was also repealed (the repeal will not affect any current projects that are subject to the FIT program).

4. The introduction of Bill 135 also proposes to amend the *Green Energy Act, 2009* to require the development of new energy and water conservation initiatives, including greater reporting on energy consumption and water usage.[114] Electricity,

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109 *Ibid* at 21.
110 *Ibid* at 17.
111 *Ibid* at 36.
112 Bill 135, *Energy Statute Law Amendment Act, 2016*, 1st Sess, 41st Leg, Ontario, 2016 [Bill 135].
113 *Electricity Act, 1998,* SO 1998, c 15, Schedule A, s 25.35, as repealed by Bill 135, *ibid*.
114 *Green Energy Act, 2009*, SO 2009, c 12, Schedule A.

water, and gas distributors will also all be required to effectively make this consumption information publicly available.

In addition to Bill 172 and Bill 135, Ontario's *Greenhouse Gas Emissions Reporting Regulation* also came into force in 2015.[115] Under this regulation reporting is required by any party producing more than 10,000 tonnes of CO_2 per year, down from 25,000 tonnes per year previously. Further, starting in 2016 petroleum product suppliers and natural gas distributors will also have reporting requirements under the Regulation.[116] Another important change resulting from Bill 135 will require the Province to establish long-term energy plans that are publicly available based on technical reports produced by the IESO.

5. QUEBEC

As mentioned above, Quebec also utilizes a cap-and-trade system and is a member of WCI. In Quebec businesses that generate 25,000 tonnes or more of CO_2 a year must comply with the cap-and-trade system.[117]

6. SASKATCHEWAN AND THE ATLANTIC PROVINCES

Currently, Saskatchewan, New Brunswick, Prince Edward Island, Nova Scotia, and Newfoundland and Labrador do not have any type of carbon pricing system. However, these provinces are still discussing climate change as Saskatchewan, New Brunswick, and Nova Scotia have each announced various emissions reduction strategies in 2015.[118]

C. PARIS CLIMATE CHANGE CONVENTION

From 30 November to 12 December 2015 delegates from 195 states that are party to the United Nations Framework Convention on Climate Change (UNFCCC) gathered in Paris, France to draft a new universal climate agreement.

1. BACKGROUND TO THE CONVENTION

The 21st Conference of the Parties (COP21) was the 21st conference of the UNFCCC. The UNFCCC was adopted in 1992 at the Rio de Janeiro Earth Summit, which saw a number of states adopt the *Kyoto Protocol*. Since Rio de Janeiro, there have been a number of conferences, including in particular COP15, which took place in Copenhagen, Denmark and which recognized the objective of keeping the global temperature increase below 2ºC. The previous conference, COP20, took place in Lima, Peru and saw member states come to an agreement about how future COP conferences would be structured.

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115 *Greenhouse Gas Emissions Reporting Regulation*, O Reg 452/09.

116 *Ibid*, s 3.

117 *GHG Regulations*, *supra* note 55, r 46.1.

118 Government of New Brunswick, *New Brunswick Climate Change Action Plan 2014-2020* (Fredericton: Government of New Brusnwick, 2014), online: <www2.gnb.ca/content/dam/gnb/Departments/env/pdf/Climate-Climatiques/ClimateChangeActionPlan2014-2020.pdf>; Government of Nova Scotia, "Climate Change Nova Scotia," online: <https://climatechange.novascotia.ca>; Government of Saskatchewan, "Meaningful Action on Climate Change Will Have to Deal with Growing International Use of Coal" (Regina: Government of Saskatchewan, 2015), online: <https://www.saskatchewan.ca/government/news-and-media/2015/april/14/climate-change>.

2. THE PARIS CONFERENCE

Canada sent a number of delegates to the Paris conference, including Prime Minister Trudeau. At the conference, Prime Minister Trudeau stated that Canada is committed to doing more to address the global challenge that climate change presents. Mr. Trudeau explained that Canada will be focusing on five principles:

- Taking action based on the best scientific evidence and advice;
- Supporting and implementing policies that contribute to a low-carbon economy, including carbon pricing;
- Working with provinces, territories, cities, and Indigenous leaders;
- Assisting the developing world in dealing with climate change; and
- Viewing climate change not just as a challenge but also as a historic opportunity.[119]

Presently Canada has pledged to cut emissions by 30 percent from 2005 levels by 2030, and to invest $2.65 billion in assisting developing countries with reducing carbon emissions.[120] However, the federal government has not yet worked out a detailed emissions plan. Mr. Trudeau met with provincial premiers on 1 March 2016 in Vancouver to discuss a federal climate change strategy. While the parties did not come up with a firm plan, the premiers agreed to begin the process of developing a plan.

As part of their participation in the conference, member states were required to submit an Intended Nationally Determined Contribution (INDC). Each INDC was intended to present a road map of the means by which the country plans to assist in limiting global warming. Before the conference began, 170 nations had submitted their INDC's.

Globally, COP21 has been touted as a success as the parties were able to reach an agreement, titled the Paris Agreement. One of the main aspects of the Paris Agreement is the consensus that Parties should work towards keeping the global increase in temperature below 2ºC, though there was also an agreement to work towards limiting the temperature increase to 1.5ºC.

The Paris Agreement includes a provision whereby developed countries will assist developing nations to combat climate change by giving them $100 billion annually. The Paris Agreement calls on parties to publish their greenhouse gas reduction targets, and the Paris Agreement will be reviewed every five years beginning in 2023. Finally, the Paris Agreement also ambitiously proposes to reach a global carbon neutral state between 2050 and 2100.[121]

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119 Prime Minister of Canada, News Release, "Canada's National Statement at COP21" (30 November 2015), online: <pm.gc.ca/eng/news/2015/11/30/canadas-national-statement-cop21>.

120 *Ibid*.

121 UNFCCC Conference of the Parties, *Paris Agreement*, UNFCCCOR, 21st Sess, UN Doc FCCC/CP/2015/L.9/Rev.1 (2015).

Most of the Paris Agreement is not binding although countries are bound and required to present updated plans with increased emissions targets, and must take stock of their plan in 2023.[122] Finally, the Paris Agreement itself will not be ratified until adopted by at least 55 of the 195 countries, representing at least 55 percent of all global GHG emitters. The agreement remains open for signature until 21 April 2017. Canada ratified the Paris Agreement on 22 April 2016.[123]

D. UPSTREAM GHG EMISSIONS ASSESSMENT BY THE NEB AND CEAA

On 27 January 2016, the federal government announced plans to revise the approval process for major projects.[124] As part of this announcement, the Federal Government set out five principles that would govern assessments in the interim:

1. No project proponent will be asked to return to the starting line – project reviews will continue within the current legislative framework and in accordance with treaty provisions, under the auspices of relevant responsible authorities and Northern regulatory boards;

2. Decisions will be based on science, traditional knowledge of Indigenous peoples, and other relevant evidence;

3. The views of the public and affected communities will be sought and considered;

4. Indigenous peoples will be meaningfully consulted, and where appropriate, impacts on their rights and interests will be accommodated; and

5. Direct and upstream greenhouse gas emissions linked to projects under review will be assessed.[125]

The inclusion of the assessment of upstream GHG emissions is significant to the upstream and midstream industries. The assessment of upstream GHG emissions essentially looks at the GHGs that are produced in the extraction and processing of the oil that the proponent is proposing to transport.

1. AFFECTED PROJECTS

In order to assess the upstream GHG emissions effects for a number of projects, the Federal Government intends to extend the time limits for assessment under the *NEBA*.[126] Under section 52(7) of the *NEBA* the Minister can extend the legislated time limit for an

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122 *Ibid.*

123 Prime Minister of Canada, News Release, "Prime Minister Concludes His Visit to New York for the Paris Agreement Signing Ceremony" (22 April 2016), online: <pm.gc.ca/eng/news/2016/04/22/prime-minister-concludes-his-visit-new-york-paris-agreement-signing-ceremony>.

124 Natural Resources Canada, "Government of Canada Moves to Restore Trust in Environmental Assessment" (Ottawa: NRC, 27 January 2016), online: <news.gc.ca/web/article-en.do?nid=1029999&tp=980>.

125 *Ibid.*

126 *NEBA*, *supra* note 3.

application for up to three months, and the Governor in Council can extend the time limit even further.[127]

Four of the major projects where the NEB or Canadian Environmental Assessment Agency (CEAA) has indicated that it plans to consider upstream GHG emissions as a part of the assessment process are as follows:

- Kinder Morgan Trans Mountain Expansion Project — the timeline for the review of this project will be extended for 4 more months to a total of 7 months. The CEAA released a draft of its review of related upstream GHG emissions estimates on 19 May 2016. Public comments on the draft report are due by 20 June 2016. The draft report concludes that upstream GHG emissions associated with the transportation capacity on the TM Project alone are unlikely to materially increase overall Canadian or global GHG emissions. However, the conclusion is dependent on a number of factors and assumptions related to future economic conditions as well as future hydrocarbon development scenarios, both nationally and globally.

- Energy East Project — this project will see an extension of both the NEB assessment process and the Governor in Council's approval process. The NEB approval extension will be for 6 months, while the Governor in Council approval extension will be for three months. This will bring the total review time to 21 months.

- Pacific NorthWest LNG Project (Petronas) — this project also was assessed in light of the interim measures, including upstream GHG emissions. Initially upstream emissions were estimated by Environment and Climate Change Canada to be in the range of 6.5 to 8.7 million tonnes of CO_2e per year.[128] The proponent provided a project-specific estimate of less than 5 million tonnes of CO_2e per year. However, in its draft assessment report the CEAA noted that at these estimates the project would represent 10 to 14 percent of provincial emissions per year.[129] Despite concluding that it could not find any measurable environmental effects in the project area, and conceding that GHG-related climate change could only result from cumulative GHG on a global basis, CEAA considered that the project is not likely to cause significant adverse environmental effects.[130] Following the receipt of comments on their draft decision, CEAA extended the review period by an additional 90 days.

127 *Ibid*, s 52(7).

128 Canadian Environmental Assessment Agency, *Pacific North West LNG: Draft Environmental Assessment Report* (Ottawa: Ministry of Environment and Climate Change, 2016), s 6.2.2, online: <www.ceaa.gc.ca/050/documents/p80032/104785E.pdf>.

129 *Ibid*, s 6.2.3.

130 *Ibid*, s 10.

- Woodfibre LNG Project — on 9 February 2016 the CEAA announced that it was seeking public comments on an analysis of anticipated GHG emissions associated with this project. The analysis

> outlines estimates of upstream GHG emissions resulting from the extraction of the project's natural gas supply and its transportation to the proposed Woodfibre LNG facility. It also includes data on direct GHG emissions taken from the Government of British Columbia's Assessment Report which is part of the substituted environmental assessment.[131]

A paper recently published by the C.D. Howe Institute has suggested that requiring the NEB to consider upstream GHG emissions in the assessment process could be an overreach of federal authority and unnecessarily intrude into areas of provincial responsibility. Further, the paper suggests that counting upstream emissions against pipeline projects will hinder, not help.[132] As such, there is a possibility the recently announced review of GHG emissions policy will be constitutionally challenged at some point in the future.

E. ALBERTA POWER PRODUCERS TERMINATING THEIR PPA INTERESTS

In late 2015 and early 2016, Alberta's major power producers announced they were terminating (or "returning") their interest in certain Power Purchase Arrangements (PPA) which were entered into when Alberta's electricity market was deregulated. Parties that have terminated their interests include: ENMAX Corporation, TCPL, ASTC Power Partnership, and Capital Power; at the time of publication of this article, all PPAs are now held by the Balancing Pool.[133] Each of the companies, listed above, have indicated that they are returning their obligations as PPA Buyers on the basis that "unprofitable market conditions are expected to continue as costs related to CO_2 emissions have increased and are forecast to continue to increase over the remaining term of the PPA Agreements."[134]

As mentioned, under the *SGER*, emissions emitters are required to be reducing their emissions and will be charged a price per tonne, a price that the government announced in June 2015 would be increasing.[135] Thus, PPA Buyers are claiming the market conditions are such that the market is no longer profitable and are relying on article 4.3 of the PPA to terminate the PPA. For the period of January 1 to March 31, the price of energy in the Province averaged \$18.11 per MWh.[136] Article 4.3(j) of the PPA states:

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131 Canadian Environmental Assessment Agency, "Public Notice: Woodfibre LNG Project – Public Comments Invited" (Vancouver: CEAA, 2016), online: <www.ceaa.gc.ca/050/document-eng.cfm?document=104774>.

132 Grant Bishop & Benjamin Dachis, "The National Energy Board's Limits in Assessing Upstream Greenhouse Gas Emissions," *CD Howe Institute E-Brief* 229 (18 February 2016), online: <https://www.cdhowe.org/sites/default/files/attachments/research_papers/mixed/e-brief_229_0.pdf>.

133 Nigel Bankes, "The Termination of Power Purchase Arrangements in Alberta: What is the Legal Position and What are the Implications of Termination?" (24 March 2016), *ABlawg* (blog), online: <ablawg.ca/wp-content/uploads/2016/03/Blog_NB_PPAs_March2016.pdf> [Bankes, "PPA"].

134 TransCanada, News Release, "TransCanada to Terminate Alberta Power Purchase Arrangements" (7 March 2016), online: <www.transcanada.com/announcements-article.html?id=2031816&t>.

135 See Part III, above.

136 Market Surveillance Administrator, "Q1/2016 Quarterly Report: January – March 2016" (29 April 2016), online: <albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-04-29%20Q1%20Quarterly%20Report.pdf>.

> Notwithstanding any of the foregoing, to the extent that a Change in Law, after giving effect thereto and to this Section 4.3, could reasonably be expected to render continued performance by the Parties to this Arrangement for the balance of the Effective Term unprofitable to the Buyer in respect of a Unit, having taken account of any compensation entitlement under Section 4.3(i) or any amount due from the Balancing Pool, then the Buyer may terminate this Arrangement and shall not be liable for, nor entitled to any Termination Payment.[137]

In order to rely on article 4.3, a PPA Buyer must be able to demonstrate that: (1) there was a change in law; (2) the change in law resulted in the owner passing on increased costs to the buyer; and (3) the buyer, having covered these costs, has come to the "reasonable expectation" that continued performance of the PPA would be unprofitable.[138] As a result of the terminations, the Balancing Pool may be left with an increase in rights and liabilities, because under section 96(3) of the *EUA* any PPA that is terminated is deemed to have been sold to the Balancing Pool and is to be held by the Balancing Pool for the purposes of the regulations.[139] The actual implications of this remain to be seen, the Balancing Pool can either manage the PPA or attempt to resell them, though the latter option seems unlikely if PPA Buyers are currently prepared to relinquish their PPA interests.

IV. ENVIRONMENTAL ISSUES AND ENVIRONMENTAL ASSESSMENT

A. *ONTARIO POWER GENERATION INC. V. GREENPEACE CANADA*[140]

In 2015, Ontario Power Generation (OPG) appealed the Federal Court's decision finding that the environmental assessment conducted in relation to the proposed four new nuclear power generation facilities at the existing Darlington Nuclear Generating Station was incomplete. The approval process for this project comes under the *Nuclear Safety and Control Act*,[141] the *Fisheries Act*,[142] and the *Navigation Protection Act*.[143]

1. BACKGROUND

OPG began its project application in 2006. On 20 March 2008, a Joint Review Panel (Panel) was established for the project, because it required the involvement of both the CEAA and the Canadian Nuclear Safety Commission (CNSC). After a period of public review, the Panel released the requirements for the project's Environmental Impact Statement, which included requirements for all five phases of the project. In September 2009 OPG filed its Environmental Impact Statement (EIS). The EIS that OPG proposed used a bounding approach, which essentially presented four different reactor technology options.

137 Bankes, "PPA," *supra* note 133 at 5 (referring to the Sheerness Power Purchase Arrangement, subject to *Electric Utilities Act*, SA 2000, c E-5.1, s 45.95 [*EUA*]).
138 Bankes, "PPA," *ibid* at 5.
139 *EUA*, *supra* note 137, s 96(3).
140 2015 FCA 186, 388 DLR (4th) 685 [*Ontario Power Generation*].
141 *Nuclear Safety and Control Act*, SC 1997, c 9 [*NSCA*].
142 *Fisheries Act*, RSC 1985, c F-14.
143 *Navigation Protection Act*, RSC 1985, c N-22.

The Panel's eventual Environmental Assessment (EA), released 25 August 2011, found that the project was not likely to cause significant adverse environmental effects, provided OPG followed the mitigation measures proposed.[144] The Responsible Authority, the federal authority who has a responsibility to ensure that an environmental assessment is carried out, subsequently upheld this finding on 8 May 2012, and as result, in August 2012, CNSC issued OPG a site preparation licence.[145]

2. FEDERAL COURT DECISION

Greenpeace Canada then brought an application for judicial review, asserting that the EA was invalid, and that the site preparation licence should not have been issued. It argued that allowing OPG to use a bounding approach made it impossible to comprehensively assess the environmental effects of the project under section 16 of the *CEAA* 2012.[146] In particular, Greenpeace Canada's contention was that OPG's EIS failed to provide enough information on which to conduct a detailed EA, because it did not look at the effects of liquid effluent, did not deal with spent nuclear fuel, and OPG failed to provide an analysis of severe common accidents stating that these would be too difficult to predict.

The Federal Court found that OPG's use of a bounding approach was reasonable. However, the Panel's EA was found to be incomplete because it did not provide enough information regarding the OPG's proposed treatment of hazardous substance emissions. The issue on appeal was whether the trial judge had applied the correct standard of review when assessing whether the Panel had considered the appropriate factors.

3. FEDERAL COURT OF APPEAL DECISION

At the Federal Court of Appeal, Justices Trudel and Ryer took a step back from the Federal Court's decision, finding that the Panel had significant leeway and that reasonableness is a low threshold. The Court found that the Panel need only give some consideration to the project's environmental effects. In fact, the majority stated "that a failure of the Panel to consider the HSE environmental effects can only be established if it is demonstrated that the Panel gave no consideration at all to those environmental effects."[147] Thus, despite the fact that there were gaps in the information OPG provided to the Panel for consideration, the majority held that these gaps did not mean the EA was non-compliant.

The dissenting opinion in this decision came from Justice Rennie, who held that,

> the Panel's conclusions and recommendations in respect of hazardous emissions did not comply with the requirements of the legislation. In the absence of evidence of the nature of contaminants, and the frequency and degree of discharge, the report could not comply with the requirements of section 16. Simply put, the conclusion that there would not be any significant adverse effects was unreasonable.[148]

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144 *Ontario Power Generation*, *supra* note 140 at para 19.
145 *Ibid* at para 20.
146 *CEAA* 2012, supra note 25, s 16.
147 *Ontario Power Generation*, *supra* note 140 at para 130.
148 *Ibid* at para 43.

For these reasons, Justice Rennie held that it was unreasonable to make a decision without proper information.

B. *COASTAL FIRST NATIONS V. BRITISH COLUMBIA (MINISTER OF ENVIRONMENT)*

In this case, Coastal First Nations — Great Bear Initiative Society and Gitga'at First Nation (CFN) sought judicial review of the Equivalency Agreement between the province of British Columbia, the British Columbia Environmental Assessment Office (EAO), and the NEB, entered into pursuant to sections 27 and 28 of the *Environmental Assessment Act* in respect of the Enbridge Northern Gateway Project.[149] CFN took issue with and challenged the Equivalency Agreement (and in particular clause 3), which purported to remove the need for proponents to get an environmental assessment certificate (EAC). CFN sought a declaration that the Equivalency Agreement was invalid and that the province needed to consult with the CFN.

1. BACKGROUND

The Equivalency Agreement between the EAO and the NEB was signed in 2008 and amended in 2010. The Parties' intention was to streamline the process for reviewable projects which require approval under both the *EAA* and the *NEBA*. The Equivalency Agreement also provided that some projects would be permitted to proceed without an EAC.

2. DECISION

CFN's submission was that the Equivalency Agreement was invalid for two reasons. First, from a statutory interpretation perspective, nothing in the *EAA* provides for or authorizes the Provincial Government to abdicate its responsibility to determine whether an environmental assessment is complete. CFN's second submission was that the Province had a constitutional obligation to consult with First Nations before engaging in action that might adversely affect First Nations' rights. The Province, in response to this, asserted that it was within the internal purview of the EAO and Executive Director to exempt certain projects from needing an EAC, while Northern Gateway Pipelines Inc. (NGP) simply asserted that the project was a federal undertaking and thus should fall exclusively within federal jurisdiction.

The Court found that "the proposed Project, while interprovincial, is not national and it disproportionately impacts the interests of British Columbians."[150] Further, the Court noted that compliance with the *EAA*, the purpose of which is to balance environmental protection with economic development, did not mean a proponent must not also comply with the *NEBA*. The *NEBA* permits a project to continue provided it complies with federal conditions.

Further, the Court agreed that the Province must maintain its authority under the *EAA*. The *EAA* assessment is clearly separated from a Provincial EAC, such that a party must successfully complete an environmental assessment *and* get an EAC. Finally, the Court

[149] *Environmental Assessment Act*, SBC 2002, c 43 [*EAA*].
[150] *Coastal First Nations*, *supra* note 39 at para 53.

found that it could not "be the intention of the legislators to allow the voice of British Columbia to be removed in this process for an unknown number of projects, when the purpose behind the *EAA* is to promote economic interest in this province, and to protect its land and environment."[151] Therefore, the Court invalidated the section of the Equivalency Agreement which removed the need for an EAC pursuant to sections 27 and 28 of the *EAA*.[152]

On the question of the duty to consult and the honour of the Crown, the Court noted that the duty to consult was not triggered simply because the Province signed the Equivalency Agreement, as there was only a thin connection to possible adverse impacts.[153] In order for the duty to consult to be triggered, it has to be clear that the Equivalency Agreement will cause adverse impacts.

However, the Court noted that the British Columbia Government had conducted no consultation with the petitioners even though it knew CFN had concerns about the project.[154] The Court found this concerning given the fact that on the Province's interpretation of the Equivalency Agreement, the Province gave up significant ability to uphold its ability to consult. For this reason, the Court found the Province had breached its duty to consult.[155] The Province was also ordered to consult with the CFN about the potential impacts of the project within the province, how these impacts might affect CFN Aboriginal rights, and how these impacts can be addressed in a manner that is consistent with the honour of the Crown and reconciliation.[156]

C. AER ENFORCEMENT ORDERS

Collectively, the following orders provide insight into the renewed focus on regulatory compliance by the AER, particularly in cases where non-compliance has contributed to releases and environmental impacts.

1. APACHE CANADA LTD.

Between 23 January 2009 and 6 November 2013, the AER issued twelve high-risk enforcement actions against Apache Canada Ltd. (Apache).[157] Apache also experienced six pipeline incidents that caused public damage or had the potential to cause public damage, between 1 June 2013 and 29 October 2014.

Apache was issued administrative penalties of $16,500 in relation to a produced water spill that was discovered in June 2013. On 26 June 2015, the AER issued an order directing that Apache take steps to improve the overall integrity of its pipeline management system, to implement a third party audit, and to submit plans for future actions.

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151 *Ibid* at para 178.
152 *Ibid* at para 180.
153 *Ibid* at para 204.
154 *Ibid* at para 206.
155 *Ibid* at para 213.
156 *Ibid* at para 215.
157 Alberta Energy Regulator, News Release, "Apache Canada Ltd Subject to AER Enforcement Action" (7 July 2015), online: <https://www.aer.ca/documents/news-releases/AERNR2015-07.pdf>.

In October 2015, Apache was charged under the *Environmental Protection and Enhancement Act*,[158] the *Public Lands Act*,[159] and the *Pipeline Act*,[160] in relation to a 25 October 2013 produced water release near Zama.

On 21 January 2014, Apache recorded a pipeline spill of approximately 1,900m³ of produced water into the nearby environment, and the following five charges were laid against Apache on 18 January 2016:

- One count under section 109(2) of *EPEA* for releasing a substance into the environment that may have caused an adverse effect;
- One count under section 110(1) of *EPEA* for failing to report the release of the substance as soon as possible;
- Two counts under section 112(1)(a) of *EPEA* for failing to take appropriate remediation measures; and
- One count under section 9(4) of the *Pipeline Regulation*[161] for failing to ensure staff and controllers were competent in leak detection technology.

All of the charges are still before the Court.

2. COAL VALLEY RESOURCES INC.

On 16 October 2015, the AER announced that charges were laid against Coal Valley Resources Inc. (Coal Valley), Sherritt International Corporation, and Sherritt International Corporation operating as Sherritt Coal for an incident that occurred in October 2013.[162] In October 2013, wastewater containment failed and some contaminated water entered the Athabasca River. As a result, on 19 November 2013 an Environmental Protection Order (EPO) was issued against Coal Valley and Sherritt International Corporation.

In addition to the EPO, the AER conducted an investigation into the mine, and on 6 March 2015 forwarded its findings to the Crown. The Crown laid the following charges:

- One count for a contravention of section 227(j) of *EPEA* for releasing a substance into the environment that caused or had the potential to cause a significant adverse effect that would constitute an offence under section 109(2) of *EPEA*;
- One count under section 227(e) of *EPEA* for failing to comply with a condition of the *EPEA* approval;

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158 *Environmental Protection and Enhancement Act*, RSA 2000, c E-12 [*EPEA*].
159 *Public Lands Act*, RSA 2000, c P-40 [*PLA*].
160 *Pipeline Act*, RSA 2000, c P-15.
161 Alta Reg 91/2005.
162 Alberta Energy Regulator, News Release, "Charges Laid Regarding October 2013 Obed Mountain Coal Mine Spill" (16 October 2015), online: <https://www.aer.ca/documents/news-releases/AERNR2015-18.pdf>.

- Two counts of contraventions of section 142(1) of the *Water Act* for failing to comply with two conditions of the *Water Act* approval; and

- Two counts of contraventions of section 56(1)(g) of the *Public Lands Act* for causing a disturbance to public land, which is an offence under sections 54(1)(e) and 54(1)(a.1).

Coal Valley appeared in court in relation to this matter in January 2016.[163]

3. NEXEN ULC

On 17 July 2015, the AER issued an EPO to Nexen ULC (Nexen), as a result of a pipeline release at Nexen's Long Lake Project (Long Lake Project).[164] The EPO required Nexen to contain the spill and take steps to prevent the further spread of the release to unaffected portions of the spill site, other waterbodies, or wetlands. The EPO was subsequently amended on 11 August 2015, after additional details pertaining to the spill became known. The amended EPO required Nexen to review and compare environmental data and complete a preliminary human health quantitative risk assessment followed by a detailed human health risk assessment.[165]

Nexen voluntarily self disclosed a number of non-compliances with its pipeline licences at the Long Lake Project site on 25 August 2015. On 28 August 2015, the AER issued an order suspending operations at the Long Lake Project site in response to the non-compliance issues.[166]

Since that time the EPO was amended by the AER on several occasions to allow Nexen to address the underlying non-compliance issues at the site. To date, no charges have been laid against Nexen.

D. BRITISH COLUMBIA PROPOSED AMENDMENTS TO CONTAMINATED SITES REGULATIONS

In late 2015, the British Columbia Ministry of Environment (MOE) issued a series of documents and consultation papers in relation to a comprehensive review of the regulations governing contaminated sites under the *Environmental Management Act*.[167] The MOE intends to use omnibus amendments to update the current soil and groundwater standards for existing and added chemicals and to create new land use categories. The amendments will include changes to contaminated soil relocation agreements. The Land Remediation Section of the MOE also released a number of updated and new guidance documents in late 2015.

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163 *Ibid*.

164 Alberta Energy Regulator, News Release, "AER Issues Environmental Protection Order to Nexen" (17 July 2015), online: <www.aer.ca/documents/news-releases/AERNR2015-09.pdf>.

165 *Ibid*; Alberta Energy Regulator, "Order Amendment #1" (Calgary: AER, 11 August 2015), online: <https://www.aer.ca/documents/orders/Nexen-EPOAmendment_1.pdf>.

166 Alberta Energy Regulator, News Release, "AER Issues Suspension Order to Nexen" (28 August 2015), online: <www.aer.ca/documents/news-releases/AERNR2015-13.pdf>.

167 *Contaminated Sites Regulation*, BC Reg 375/96 [*CSR*].

The *Contaminated Sites Regulation* contains mandatory standards that outline the permissible residual contaminant soil concentrations for remediated contaminated sites.[168] These standards vary in accordance with particular categories of land use and many of the schedules have not been updated since their initial introduction in the mid-1990s. The MOE has indicated it intends to update standards on a mandatory five year cycle.

Initially, the MOE proposed a single standard (15 percent level of effects) for Wildlands. In December 2015 the MOE released a proposal to expand the categories of land use by creating two-tier Wildlands standards, dependent on whether the lands are "Natural Wildlands" or "Reverted Wildlands." The site will be Reverted Wildlands if it has been subject to *CSR* Schedule 2 activities. By introducing less stringent standards for Reverted Wildlands, site owners may be able to qualify for certificates of compliance more easily than under the prior proposed regime. However, on the whole, the applicable standards under the amended *CSR* are expected to become more stringent and will cause more sites to require screening or site-specific assessments.

The amendments will also divide residential land into two tiers: low density residential land use and high density residential land use. Recently, the MOE consulted industry and stakeholders on the optimum length of a transition period for the implementation of the amended standards to the *CSR*.[169] During the implementation period, entities can opt to use either the previous or amended *CSR* standards.

V. ABORIGINAL LAW AND THE DUTY TO CONSULT

A. *FORT NELSON FIRST NATION V. BRITISH COLUMBIA (ENVIRONMENTAL ASSESSMENT OFFICE)*[170]

The Fort Nelson First Nation (FNFN) advanced an application for judicial review wherein it alleged that the British Columbia EAO should have consulted with the FNFN in reaching its conclusion that the Komie North Mine project was not a reviewable project under the *Reviewable Projects Regulation*.[171] The Komie North Mine is a sand and gravel pit project proposal by Canadian Silica Industries and Jeffery Bond (CSI).[172] The project proposes to extract silica to be used in the process of hydraulic fracing. Part of the project was planned to take place within traditional FNFN territory under Treaty 8.

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168 British Columbia, Ministry of the Environment, "CSR Omnibus Standards Updating Supplemental Consultation Document: Proposal to Derive Wildlands Soil Quality Standards for Use Under the Contaminated Sites Regulation Based on Two Tiers of Environmental Protection" (Victoria: Environmental Protection Division, December 2015), online: <www2.gov.bc.ca/assets/gov/environment/air-land-water/site-remediation/docs/requests-for-comments/consultation_paper_two_tier_wildlands_standard.pdf>.

169 The period for comment ended 29 February 2016 : Government of British Columbia, "CS e-Link Recent Messages" (26 February 2016), online: <www2.gov.bc.ca/gov/content/environment/air-land-water/site-remediation/contaminated-sites/cs-e-link-recent-messages>.

170 2015 BCSC 1180, [2015] 4 CNLR 104 [*Fort Nelson*].

171 *Reviewable Projects Regulation*, BC Reg 370/2002.

172 *Fort Nelson*, *supra* note 170 at para 1.

1. BACKGROUND

Throughout CSI's application process, FNFN repeatedly raised concerns with the Minister of the Environment that the project should be reviewed, and that FNFN should be consulted before a decision is made.[173] However, the EAO determined that the project was not reviewable on the basis that the producible capacity in the application, as proposed by the proponent, was below the reviewable limit.[174] Further, the EAO held that because the decision was based on the EAO's interpretation of Table 6 in the Regulation, there was no duty to consult.

2. ISSUE

Two issues were raised in the application. First, whether the EAO's decision to accept CSI's assertion that the producible capacity was below the limit was reasonable, and secondly, whether the EAO owed a duty to consult when determining whether a project is reviewable.[175]

3. DECISION

On the issue of the interpretation of "producible capacity," CSI asserted that this simply meant the capacity that CSI used or sold, as opposed to everything that was extracted. The Court found that this assertion was unreasonable according to statutory interpretation principles, and further was not supported based on CSI's own previous interpretation of the provision.[176] The Court also emphasized and agreed with FNFN's contention that this interpretation was unreasonable because it undercut the environmental protection purposes of the *EAA* and the EAO thus failed to recognize the potential cumulative physical impact of the project on the environment.

The Court further found that the Province needed to consult with FNFN on whether the project was reviewable. The Court held that the decision of whether a project is reviewable not only has the potential to directly adversely affect FNFN's Treaty 8 rights, but that there could also be a spillover effect if there was a corresponding increase in fracking.[177] For this reason, the Court held that the Ministry's decision about whether a project is reviewable is the type of decision that is akin to a strategic high-level decision, which triggers the duty to consult.[178] The Court set aside the EAO's decisions relating to the Komie North Mine and declared that the Crown had failed to fulfill its duty to meaningfully consult with FNFN.

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173 *Ibid* at paras 8–9.
174 *Ibid* at para 11.
175 *Ibid* at paras 13–14.
176 *Ibid* at para 198.
177 *Ibid* at para 250.
178 *Ibid* at para 271.

B. *PROPHET RIVER FIRST NATION v. CANADA (ATTORNEY GENERAL)*[179]

This application for judicial review was brought by a number of Treaty 8 First Nations in relation to the proposed Site C Clean Energy Project (Site C Project). The Applicants contested the Governor in Council's decision that the significant adverse environmental effects of the Site C Project were justified in the circumstances.

1. BACKGROUND

The Site C Project is a proposal by BC Hydro for the construction of a dam and generating station on the Peace River near Fort St. John, British Columbia. BC Hydro submitted its project description to the EAO and the CEAA on 18 May 2011. Both the federal and provincial environmental offices were involved because there were potential environmental impacts to or upon the environment, fish, and transportation.[180] The EAO and CEAA decided that they would cooperatively assess the Site C Project by way of a Joint Review Panel. On 1 May 2014 the Joint Review Panel advised the Minister under section 52(4) of the *CEAA* 2012 that the project was likely to cause significant adverse effects on fishing, hunting, traditional land use, current lands and resources, cultural heritage resources, and ecological communities and habitats.

The Applicants were given an opportunity to convey to the Minister of the Environment their concerns about the project in August 2014. In their letter to the Minister, the Applicants explained that "they believed their treaty rights would be infringed by the Project and that such an infringement required justification under the *Sparrow* test."[181] The Applicants received no response from the Minister of the Environment and on 14 October 2014 the Governor in Council released its decision finding that the potential significant adverse environmental effects were justifiable.

2. ISSUE

The issues for the Court centred on whether the Governor in Council had the jurisdiction to decide if the Site C Project would infringe the Applicants' treaty rights, and correspondingly whether the Applicants were owed a duty to consult in light of the potential infringement of their treaty rights. The Court applied the correctness standard of review in regard to the existence of the duty to consult, and the reasonableness standard in assessing the adequacy of consultation.

3. DECISION

In terms of the Governor in Council's authority, the Court recognized that the jurisprudence demonstrates that decisions of the Governor in Council are typically owed considerable deference. Further, the Court noted that it could not properly deal with a treaty right infringement claim on this application without a full trial. However, the Court found,

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179 *Prophet River First Nation v Canada (AG)*, 2015 FC 1030, 97 CELR (3d) 23 [*Prophet River*].
180 *Prophet River*, *ibid* at paras 7–9. For the *Sparrow* test, see *R v Sparrow*, [1990] SCR 1075.
181 *Prophet River*, *ibid* at para 23.

without making a determination on the issue of infringement, a potential infringement of First Nations treaty rights that ought to have been considered as a part of the consultation process. As such, it was unreasonable for the Governor in Council to have not dealt with the potential infringement of treaty rights.

On the issue of consultation, the Court noted that this case would have been on the deep end of the spectrum. However, the Court also noted that discussions with the Applicants in relation to the Site C project had been substantive. The Applicants were involved in the process, had received almost six million dollars in capacity funding and had met with BC Hydro approximately 177 times. On this basis, the Court held that BC Hydro's consultation was both extensive and conducted in good faith. Therefore, the Court dismissed the application for judicial review. In conclusion, the Court noted that "[a] commitment to the process does not require a duty to agree — what is required is good faith efforts to understand the concerns of the Applicants."[182]

C. *CHIPPEWAS OF THE THAMES FIRST NATION v. ENBRIDGE PIPELINES INC.*[183]

The Chippewas of the Thames First Nation (Chippewas) brought this appeal on the basis that the NEB did not have the jurisdiction to authorize Enbridge to proceed with the Line 9B Reversal and Line 9 Capacity Expansion Project (the Line 9 Project) without fulfilling its duty to consult because the Crown effectively delegated this duty to the NEB. This case was triggered by the NEB's approval of Enbridge's application to reverse a pipeline, increase Line 9's capacity, and to begin transporting heavy oil.

1. BACKGROUND

In conjunction with the regulatory process, Chippewas were granted intervener status and received funding to participate in consultation with Enbridge. However, on 27 September 2013, Chippewas requested that the Crown conduct its own consultation, contending that the Crown was required to consult under the *NEBA*. Despite this contention, the Crown did not reply to Chippewas' request and continued to simply observe the hearing process. Finally, on 30 January 2014 it stated that it would rely on the Board to address any potential Aboriginal impacts. Not long after this response the Board acknowledged that the Line 9 Project could pose a potential threat to Chippewas' land but such impact would be minimal and could be appropriately mitigated. Accordingly, the Line 9 Project was approved under section 58 of the *NEBA*.

2. DECISION

The majority in this decision determined that tribunals are not required to assess how the duty to consult is carried out if the Crown is not a party to the proceedings. In coming to this conclusion, the Court held that the *Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council*[184]

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182 *Ibid* at para 70.

183 2015 FCA 222, [2016] 3 FCR 96 [*Chippewas*], leave to appeal to SCC granted, 2016 CarswellNat 597 [*Chippewas* Leave].

184 2010 SCC 43, [2010] 2 SCR 650 [*Rio Tinto*].

decision did not establish that a tribunal or board must always make *Haida* determinations.[185] The Court also distinguished the *Rio Tinto* and *Standing Buffalo Dakota First Nation v. Enbridge Pipelines Inc.*[186] decisions on the basis that in the latter decision, the Crown did not participate in the process, and that the remedial capacity of the tribunals differed significantly. Based on this distinction, the Court found that the decision in *Rio Tinto* had not been overruled by the decision in *Standing Buffalo*. Further, the Court held that the "essential factual context in *Standing Buffalo* is indistinguishable from the factual context in this appeal," and for this reason *Standing Buffalo* should be followed.[187]

3. DISSENT

However, Justice Rennie dissented, finding that this decision raised the novel question of the role of a tribunal in assessing the duty to consult when the Crown is not a party to the application. Further, Justice Rennie found that *Rio Tinto* should be interpreted to mean that boards or tribunals should consider whether consultation was both required and if it has taken place. Thus, in this case, "the Board should have considered whether there was a duty to consult, and if so whether it had been fulfilled, and granted approval only if there were no unfulfilled duty to consult."[188] Finally, Justice Rennie also noted that the majority's opinion effectively creates a "disincentive to timely, good faith and pragmatic consultations, and undermines the overarching objective of reconciliation."[189]

On 10 March 2016, Chippewas were granted leave to appeal the decision to the Supreme Court of Canada, where it will be considered with *Clyde River (Hamlet of) v. TGS-NOPEC Geophysical Co. ASA* (TGS),[190] discussed below. This appeal is tentatively scheduled to be heard on 30 November 2016. An application to state a constitutional question filed by Chippewas on 7 April 2016 was dismissed by the Court with costs on 28 April 2016.

D. *CLYDE RIVER (HAMLET) V. TGS-NOPEC GEOPHYSICAL CO. ASA (TGS)*

The hamlet of Clyde River brought this application for judicial review in relation to the NEB's approval of a Geophysical Operations Authorization (GOA) for TGS-NOPEC Geophysical Company ASA (TGS), Petroleum Geo-Services Inc. (PGS), and Multi Klient Invest (MKI).[191] The Respondents had applied for the GOA because it would allow them to conduct seismic studies in Baffin Bay and the Davis Strait. The Appellants main concern with the decision to issue the GOA was that the NEB had allegedly failed to properly exercise its duty to consult.

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[185] *Chippewas*, *supra* note 183 at para 33.
[186] 2009 FCA 308, [2010] 4 FCR 500 [*Standing Buffalo*].
[187] *Chippewas*, *supra* note 183 at para 56.
[188] *Ibid* at para 111.
[189] *Ibid* at para 119.
[190] 2015 FCA 179, 94 CELR (3d) 1 [*Clyde River*], leave to appeal to SCC granted, 2016 CarswellNat 599.
[191] *Ibid* at para 4.

1. BACKGROUND

The Court determined that the hamlet of Clyde River had standing to challenge the GOA decision on the basis that the GOA application raised a serious issue and it was an issue in which the hamlet had a clear stake.[192] With respect to the duty to consult, the Court noted that the standard of review for whether there is a duty to consult is correctness, while the adequacy of the consultation is reviewable on the reasonableness standard.[193] The Court found that while the Crown recognized it was required to engage in consultation it did not actually engage in any additional or independent consultation outside the consultation conducted by the Respondents.[194] Thus, the central issues in terms of consultation were whether the scope of consultation was required, and whether the Crown adequately met its duty by relying on the actions of the Respondents to carry out this duty.

2. DECISION

In its decision, the Court noted that "adequate consultation does not require agreement," that there was no baseline on which to compare such evidence, and that the NEB has the authority to assess applications on a case-by-case basis.[195] Further, the Court noted that throughout the application process, the proponents were required to provide substantial and detailed information about the project to Aboriginal groups, to respond to comments received by these groups, and to address their concerns. In light of this, the Court held that the process used by the NEB afforded any potentially affected Aboriginals with adequate and meaningful consultation, thus meeting the Crown's duty to consult.[196]

The final issue was whether the NEB provided inadequate reasons for why it issued the GOA.[197] The GOA application was made under section 5(1)(b) of the *COGOA*.[198] *COGOA* is legislation that governs petroleum exploration in waters subject to federal jurisdiction. The Applicant tried to assert that the Crown was required to conduct a Strategic Environmental Assessment prior to approving the GOA.[199]

The Court again disagreed with Clyde River's submission, finding instead that the NEB's reasoning was primarily based on the environmental assessment, which sufficiently addressed the potential impacts of the project in light of the Aboriginal rights to harvest wildlife.[200] Further, the Court noted that the Applicant had not produced any evidence to contradict the extensive evidence provided by the proponents. Cumulatively, based on these reasons, the Court dismissed the application for judicial review, finding that the potential impact on Aboriginal rights had been both recognized and considered.[201]

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192 *Ibid* at para 15.
193 *Ibid* at paras 34–35.
194 *Ibid* at para 70.
195 *Ibid* at paras 79–81.
196 *Ibid* at para 92.
197 *Ibid* at para 100.
198 *COGOA*, *supra* note 4.
199 *Clyde River*, *supra* note 190 at para 101.
200 *Ibid* at para 102.
201 *Ibid* at para 119.

On 10 March 2016, the Supreme Court of Canada granted Clyde River leave to appeal this decision. As indicated, the appeal will be heard along with the *Chippewas* decision discussed above. The appeal hearing is tentatively scheduled for 30 November 2016.[202]

E. *BLUEBERRY RIVER FIRST NATIONS V. BRITISH COLUMBIA*[203]

In this decision, Blueberry River First Nation (BRFN) applied to the Court seeking an interlocutory injunction to prevent the Government of British Columbia from auctioning off 15 Timber Sale Licenses (TSL).[204] The crux of BRFN's contention was that the cumulative effects of this type of industrial development would effectively make it impossible for First Nations to meaningfully exercise their rights in their territory.[205] In this case, the BRFN territory is subject to Treaty 8.

The issue for the Court was whether BRFN's claim met the three criteria for obtaining an interlocutory injunction set out in as *RJR-MacDonald Inc. v. Canada (Attorney General).*[206] The Court concluded that clearly the first criteria, whether there was a serious issue to be tried, was met because the question was essentially whether the cumulative effect of the industrial development in BRFN's territory breached BRFN's treaty rights.[207] The Court also found the second criteria was made out on the basis that it could be presumed that BRFN would likely suffer a loss, which could be considered irreparable.[208]

However, the Court found the Applicants could not make out the final criteria in *RJR-MacDonald*, balance of convenience.[209] On this point, the Court noted that there had been previous opportunities for BRFN to raise their objections but they had not.[210] Further, the potential TSL licensees had relied on BRFN's lack of objection to mean that the TSL auction would proceed.[211] In coming to this conclusion, the Court also focused on the relationship between the alleged treaty breach and the activity that BRFN were trying to enjoin.

The TSLs that were to be auctioned only represented 1 percent of the BRFN's traditional territory.[212] Therefore the Court found there was not a sufficient enough connection between the actual TSLs at issue and the claimed cumulative effects and denied BRFN's application for an injunction.[213] The Court left open the possibility that BRFN could be granted an injunction in the future if they were to claim a more general and wide-ranging hold on industrial activity in the area.

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202 *Chippewas* Leave, *supra* note 183.
203 2015 BCSC 1302, [2015] 4 CNLR 1 [*Blueberry River*].
204 *Ibid* at para 1.
205 *Ibid* at para 2.
206 *Ibid* at para 13, citing *RJR-MacDonald Inc v Canada (Attorney General)*, [1994] 1 SCR 311 [*RJR-MacDonald*].
207 *Blueberry River*, *ibid* at para 39.
208 *Ibid* at para 45.
209 *Ibid* at para 54.
210 *Ibid*.
211 *Ibid* at para 55.
212 *Ibid* at para 58.
213 *Ibid* at para 65.

F. *BLUEBERRY RIVER FIRST NATIONS V. MINISTER OF NATURAL GAS DEVELOPMENT*

On 20 November 2015, the BRFN filed a petition with the British Columbia Supreme Court requesting that the Court quash or set aside a decision of the Minister of Natural Gas Development (Minister of Natural Gas Development) under section 78.1 of the *Petroleum and Natural Gas Act*[214] wherein the government entered into a Long Term Royalty Agreement (LTRA) with Progress Energy Canada Ltd. (Progress) and four other parties, on 20 May 2015.[215] The petition also requests a declaration that the Crown owes a duty to consult and accommodate BRFN with respect to the subject matter of the Minister's decision to enter into the LTRA.[216]

1. BASIS OF THE PETITION

BRFN are located in northeastern British Columbia and are party to Treaty No. 8. According to their petition the BRFN traditional mode of life includes hunting, fishing, trapping, gathering, camping, teaching, and otherwise living off the land.

The LTRA that led to this petition is an agreement on behalf of the Government of British Columbia, Progress, Indoil Montney Ltd., Japex Montney Ltd., Petroleum Brunei Montney Holdings Limited, and Sinopec Huadian Montney Limited Partnership, often collectively known as the North Montney Joint Venture (NMJV). This LTRA is the first agreement the government has entered into under section 78.1 of the *PNGA*, which allows the Minister to enter into agreements with private parties and establish the royalties they will pay to the provincial government on petroleum or natural gas produced from specified locations.[217] Effectively, the LTRA creates a favourable provincial royalty regime for NMJV and stipulates the amount of investments the parties must make. The project is tied to the Pacific NorthWest LNG export facility and the natural gas produced under the LTRA is intended to be used to meet the production requirements of the Pacific NorthWest LNG export facility.

BRFN alleges the Government did not consult with them at any point in relation to this decision or the LTRA.[218] BRFN suggests that this is a violation of the Government's duty to consult as the LTRA is conduct which might adversely affect the exercise of BRFN's treaty rights. BRFN also submits that the decision may also have triggered the Government's duty to accommodate, under *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*.[219] In their petition the BRFN suggest that the duty to consult was owed in relation to the LTRA decision because the duty to consult extends to strategic, higher level decisions under *Rio Tinto*.[220]

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214 *Petroleum and Natural Gas Act*, RSBC 1996, c 361 [*PNGA*].

215 Letter from Chief Marvin Yahey to Rich Coleman, Minister of Natural Gas Development, and Mary Polak, Minister of Environment (20 November 2015), online: <https://a100.gov.bc.ca/appsdata/epic/documents/p392/d38106/1414170289891_ZXZPJKQpsCJ7p994vTQyyJhsM8TBWSnzlv34wMyC67yCBwdyhKHr!-351597226!1414168702186.pdf> [BRFN Petition]; *PNGA*, *ibid*.

216 BRFN Petition, *ibid* at 9.

217 *PNGA*, *supra* note 214.

218 BRFN Petition, *supra* note 215 at 1.

219 *Ibid* at 2, citing *Mikisew Cree First Nation v Canada (Minister of Canadian Heritage)*, 2005 SCC 69, [2005] 3 SCR 388.

220 *Rio Tinto*, *supra* note 184.

The petition further alleges that the LTRA will result in a significant increase in the amount of development in the Montney area and that this will impact the BRFN's ability to maintain their traditional way of life. On this basis the BRFN submit that they should have been consulted, at least to some degree, in relation to the LTRA. The BRFN alleges the Government's failure to engage in any consultation is grounds for both an order setting aside the LTRA and a declaration that the Government owes a duty to consult and accommodate the BRFN with respect to decisions of this magnitude that may take place in parts of their traditional territory.

A decision in relation to this petition has not been issued yet by the British Columbia Supreme Court.

G. *O'CHIESE FIRST NATION V. ALBERTA ENERGY REGULATOR*[221]

The O'Chiese First Nation (OCFN) brought forward two applications seeking permission to appeal decisions of the AER wherein the AER approved two natural gas pipelines for Shell Canada Limited (Shell) despite the concerns of the OCFN.

1. BACKGROUND

By way of a decision dated 9 July 2015 the AER approved two small interprovincial pipelines: the Rocky 5 and 6 pipelines (Pipeline Decision). Rocky 5 is approximately 1.96 km in length and Rocky 6 is 1.08 km in length.[222] The AER's second decision, also dated July 9, 2015, approved Rocky 24 which was an application for a mineral surface lease (MSL) and licence of occupation (LOC) under the *Public Lands Act*.[223]

In relation to Shell's original applications the Government of Alberta's Aboriginal Consultation Office determined either that no consultation with the OCFN was required or that the consultation Shell had conducted was adequate. The AER also reached both of these decisions without holding a public hearing; despite the fact the OCFN raised concerns with respect to the two pipelines. The OCFN sought leave to appeal both decisions to the Alberta Court of Appeal.

On appeal, in relation to the Pipeline Decision the AER held that the OCFN was not eligible for a regulatory appeal under sections 36 or 28 of the *Responsible Energy Development Act* because the OCFN was not a person directly and adversely affected by an appealable decision.[224] In relation to the Rocky 24 Decision the AER held the OCFN was not "directly and adversely affected" by a decision under the *Public Lands Act*.[225]

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221 2015 ABCA 348, [2016] 1 CNLR 186 [*O'Chiese*].
222 *Ibid* at para 6.
223 *Ibid* at para 13.
224 *Ibid* at para 2; *Responsible Energy Development Act*, SA 2012, c R-17.3 [*REDA*].
225 *O'Chiese*, *ibid* at para 3; *PLA*, *supra* note 159.

2. ISSUE

The issue on this appeal was whether the AER had erred in law in holding that the OCFN were not eligible for a regulatory appeal because they were not directly and adversely affected by the AER decisions.[226]

3. DECISION

The Court of Appeal confirmed the limited jurisdiction of the Court and reiterated that questions of fact or mixed fact and law under *REDA* are not questions that are subject to appellate review absent an extricable question of law.[227] Further, the Court noted that there are varying degrees of deference owed to decisions of the AER, based on whether it is a question of law or jurisdiction and whether the AER has knowledge and expertise.

The Court of Appeal noted that the AER had determined that the OCFN had not presented any evidence to establish that its rights would be directly and adversely affected by the AER approvals. Because the question on this appeal was not the adequacy of the duty to consult, but whether the obligation of consultation was owed and discharged, it was found that the fact that the OCFN failed to show how it would be directly and adversely affected meant it could not request a regulatory appeal. Lastly, the Court noted that "the mere fact that the developments in question are located within the OCFNCA does not mean that the Approvals 'directly and adversely' affect the O'Chiese First Nation."[228]

H. TRUTH AND RECONCILIATION COMMISSION PAPER

The participation of First Nations groups in respect of the approval process for new energy projects has taken on increasing prominence as the rights of First Nations have become better defined, coupled with Canadian courts' increasing focus on the goal of reconciliation of Crown and First Nations' interests. The Truth and Reconciliation Commission of Canada (TRC) was established in 2008 as a condition of the Indian Residential Schools Settlement Agreement. A product of six years of work — which involved gathering statements from 6,750 witnesses — the TRC presented its conclusions in June 2015. The TRC released its final report, *Honouring the Truth and Reconciling for the Future* (*TRC Report*) in December 2015.[229]

The TRC views reconciliation as an ongoing course towards maintaining respectful relationships. The framework for reconciliation must encompass "Canada's political and legal systems, educational and religious institutions, the corporate sector and civic society."[230] The *TRC Report* includes 94 policy recommendations, termed "Calls to Action" which Prime Minister Justin Trudeau has stated the Federal Government will fully

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226 *Ibid* at para 23.
227 *Ibid* at para 26.
228 *Ibid* at para 44.
229 Truth and Reconciliation Commission of Canada, *Honouring the Truth, Reconciling for the Future: Summary of the Final Report of the Truth and Reconciliation Commission of Canada* (Ottawa: TRCC, 2015), online: <nctr.ca/assets/reports/Final%20Reports/Executive_Summary_english_Web.pdf> [*TRC Summary*]. All TRC reports are available online: <nctr.ca/reports.php>.
230 *Ibid* at 21.

implement.[231] At this time, it is not clear how the Federal Government intends to implement the recommendations.

While many of the *TRC Report*'s recommendations focus on government creation of programs and implementing change, at least four of the recommendations relate to the energy industry. The *TRC Report* calls for equity for Aboriginal peoples in the legal system. Recommendations 50 to 52 expand upon this by calling on the federal or provincial governments to:

- Establish Aboriginal law institutes to develop Indigenous law and access to justice that respects Aboriginal culture;

- Increase transparency through publication of legal opinions that it intends to act upon in relation to the scope and extent of Aboriginal treaty rights;

- Accept Aboriginal title claims "once the Aboriginal claimant has established occupation over a particular territory at a particular point in time";[232] and

- Establish a legal principle that as soon as Aboriginal title has been established, the burden of proof in relation to limitations on title rights falls on the party asserting the limitation.[233]

Further, the TRC challenges Canada's corporate sector to adopt the *United Nations Declaration on the Rights of Indigenous Peoples* and apply it to corporate policies and operational activities involving Indigenous people or related lands and resources.[234] Adoption of this framework includes, but is not limited to:

> i. [Committing] to meaningful consultation, building respectful relationships, and obtaining the free, prior, and informed consent of Indigenous peoples before proceeding with economic development projects.
>
> ii. [Ensuring] that Aboriginal peoples have equitable access to jobs, training, and education opportunities in the corporate sector, and that Aboriginal communities gain long-term sustainable benefits from economic development projects.
>
> iii. [Educating] … management and staff on the history of Aboriginal peoples [culture and law — requiring] skills-based training in intercultural competency, conflict resolution, human rights, and anti-racism.[235]

231 Prime Minister of Canada, News Release, "Final Report of the Truth and Reconciliation Commission of Canada" (15 December 2015), online: <pm.gc.ca/eng/news/2015/12/15/final-report-truth-and-reconciliation-commission-canada>; Truth and Reconciliation Commission of Canada, *Truth and Reconciliation Commission of Canada: Calls to Action* (Winnipeg: TRCC, 2015).

232 *TRC Summary*, *supra* note 229 at 215.

233 *Ibid* at 327–28.

234 *Ibid* at 336–37.

235 *Ibid* at 337.

While the impact of the directives is still uncertain, it is likely to embolden Aboriginal groups in respect of the duty to consult and scope of requested accommodation of Aboriginal interests in regard to the current and future development of Canada's natural resources.

Manitoba is the first province to legislate in accordance with the TRC's recommendations. Manitoba's Aboriginal and Northern Affairs Minister introduced *The Path to Reconciliation Act* into the Manitoba legislature on 25 February 2016.[236] The *TRC Act* imports the principles of respect, engagement, understanding, and action. Reconciliation is defined as "the ongoing process of establishing and maintaining mutually respectful relationships between Indigenous and non-Indigenous peoples in order to build trust, affirm historical agreements, address healing and create a more equitable and inclusive society."[237] The *TRC Act* received Royal Assent on 15 March 2016. The responsible minister is tasked with advancing reconciliation through making recommendations, promoting initiatives, and encouraging recognition of the contributions of Indigenous peoples to the founding of Manitoba.[238] Additionally, the minister must prepare an annual progress report detailing government actions taken to advance reconciliation.[239] The responsible minister must table the report and make it publicly available.[240]

VI. INTERPLAY BETWEEN ADMINISTRATIVE LAW AND COMMERCIAL LAW

A. BANKRUPTCY AND INSOLVENCY

1. *REDWATER ENERGY CORPORATION RE*[241]

Arguably one of the most significant Canadian energy decisions of 2016 relates to the insolvency and resulting litigation involving Redwater Energy Corporation (Redwater) and the AER. Released on 19 May 2016 and now under appeal, the reasons of Chief Justice Wittman of the Alberta Court of Queen's Bench found that receivers and trustees may renounce uneconomic wells and facilities of insolvent entities, allowing them to avoid the associated abandonment and reclamation obligations related to such assets. The decision has greatly impacted the ability of the AER to enforce its regulatory scheme in cases where a company avails itself of the federal bankruptcy legislation.

a. Background

Redwater was a publicly listed junior oil and gas company that had credit facilities with Alberta Treasury Branches and went into receivership and eventually bankruptcy, with Grant Thornton LLP being appointed as receiver and later, trustee (the Receiver). The Receiver, upon its appointment, determined that most of the assets were uneconomic and unlikely to

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236 Bill 18, *The Path to Reconciliation Act*, 5th Sess, 40th Leg, Manitoba, 2016 (assented to 15 March 2016). SM 2016, c 5 [*TRC Act*].
237 *Ibid*, s 1(1).
238 *Ibid*, s 3(1).
239 *Ibid*, s 5(1).
240 *Ibid*, s 5(2).
241 2016 ABQB 278, (*sub nom Grant Thornton Ltd v Alberta Energy Regulator*) 33 Alta LR (6th) 221 [*Redwater*].

be sold and thus purported to renounce any interest in these assets (the Renounced Assets), pursuant to section 14.06 of the *Bankruptcy and Insolvency Act.*[242] The Receiver indicated to the AER that as a result of the renunciations, neither the Receiver nor Redwater's estate had any further obligations pertaining to the Renounced Assets.

This position was met with strenuous objections by the AER, who reiterated that the Receiver must continue to abide by the requirements of the *Oil and Gas Conservation Act*,[243] the *Pipeline Act*,[244] and the *EPEA*.[245] The AER took the position that the responsibility for end- of-life obligations attaches once a licence is issued and that this responsibility cannot be avoided through insolvency, and issued abandonment and closure orders (the Orders) requiring the Receiver's compliance. The AER's concern was that if the type of action the Receiver was proposing was allowed, the entire orphan well scheme in Alberta could collapse.

Ultimately, the case pitted the provincial regulatory framework, administered and enforced by the AER, against federal insolvency legislation. Under the provincial regulations, receivers and trustees are included within the definition of "licensee" and there is process for any party to renounce assets.[246] Further, the AER may require security deposits being posted prior to the approval of a licence transfer where parties' Liability Management Rating (LMR), being the ratio of deemed assets and deemed liabilities, falls below 1.0 on a post-transfer basis.[247] The purpose of the requirement was to ensure that licensees maintain an adequate asset base to cover the costs of performing end-of-life obligations.

b. Decision

The case turned on the constitutional doctrine of paramountcy, which is applicable when

> otherwise validly enacted federal and provincial legislation cover the same or similar subject matter, but there is a conflict or genuine inconsistency between the legislation or the operational effects of the provincial legislation are incompatible with federal legislation, the federal legislation prevails and the provincial law is rendered inoperative to the extent of the conflict or inconsistency with the federal law.[248]

Since the Court interpreted section 14.06 of the *BIA* as providing a process whereby the Receiver could, in some circumstances, validly renounce interests in real property, and since the licences at issue were found to be an interest in real property (constituting the underlying wells, facilities, and pipelines), the Court found the federal and provincial legislation to be in conflict.[249] Since the provincial legislation contained no procedure to allow the receiver to renounce the Renounced Assets in an insolvency scenario; whereas the federal law contemplated exactly such a scenario, the Court held that the federal law must prevail given the direct operational conflict. As a result the Court concluded the provincial regulatory

242 RSC 1985, c B-3 , s 14.06 [*BIA*].
243 RSA 2000 c O-6 [*OGCA*].
244 *Pipeline Act*, *supra* note 160.
245 *EPEA*, *supra* note 158.
246 *OGCA*, *supra* note 243, s l(l)(cc); *Pipeline Act*, *supra* note 160, s l(l)(n).
247 Alberta Energy Regulator, "Licensee Liability Rating (LLR) Program and Licence Transfer Process," Directive 006 (Calgary: AER 2013).
248 *Redwater*, *supra* note 241 at para 95.
249 *Ibid* at para 155.

framework was inoperable to the extent of the conflict. The Court further ruled that the provincial regulatory framework also frustrated the legislative purpose of the federal *BIA*, in that: (1) including receivers and trustees within the provincial definition of "licensee" effectively created a super-priority in favour of the AER over any other creditor claims, (2) not permitting the Receiver to renounce the Renounced Assets potentially places the Receiver at personal financial risk, and (3) requiring compliance with Orders and the provincial laws or the payment of security deposits prior to the approval of licence transfers impairs the ability of the Receiver to fulfill its mandate.[250]

Additionally, the Court characterized the Orders as essentially monetary in nature, due to it being "sufficiently certain" that the AER would seek reimbursement for the costs of compliance in carrying out the abandonment and reclamation work on the Renounced Assets.[251] This means that the Orders are provable claims in bankruptcy, with the implication that the AER is an unsecured creditor in this regard.

Absent the reversal on appeal of the Court's decision in *Redwater*, the implications are such that: (1) the costs to abandon, remediate, and reclaim the Renounced Assets will not be paid out of the estate of Redwater, and (2) the Renounced Assets will most likely become orphans and the liability for remediation would fall to the Orphan Well Fund, which is funded by industry. Further, since a security deposit is not required to be posted with the AER on the transfer of licensed assets for parties with a LMR of under 1.0, it is possible that secured lenders will now be more likely to push debtors into insolvency proceedings, knowing that they have priority over the sales proceeds and that such sales processes cannot be vetoed by the AER. The decision is currently under appeal to the Alberta Court of Appeal as of the date of this article with a decision of the Court of Appeal likely to be released sometime in late 2017. The appeal of the case remains one to watch, given its broad implications to all energy industry stakeholders.

B. NATURAL RESOURCES AND SURFACE RIGHTS

1. *REMINGTON DEVELOPMENT CORPORATION V. ENMAX POWER CORPORATION*

Remington Development Corporation (Remington) applied to appeal a decision of the Alberta Utilities Commission (AUC) which denied ENMAX Power Corporation's (ENMAX) application to have two inner city transmission lines rerouted and removed from lands owned by Remington.

The application to, and decision of the AUC resulted from an Order of the Alberta Court of Queen's Bench which held that Remington had the contractual right to terminate the underlying right of way agreement (ROW Agreement). The validity of the ROW Agreement was the subject of protracted litigation before the Alberta Court of Queen's Bench[252] and the

[250] *Ibid* at para 182.
[251] *Ibid* at para 173.
[252] *Remington Development Corp v Enmax Power Corp*, 2011 ABQB 694, 57 Alta LR (5th) 217 [*Remington* I].

Alberta Court of Appeal[253] and resulted in ENMAX being directed to apply to the AUC to have the lines removed from the lands owned by Remington.[254]

a. Background

The transmission lines were originally installed on the property (then owned by Canadian Pacific Railway (CP)) by ENMAX's predecessor Calgary Power Ltd. pursuant to a ROW Agreement that allowed either party to terminate the agreement upon the provision of notice. In 2002, Remington purchased the lands from CP with the intention of ultimately redeveloping the lands. The purchase of the lands included an assignment of the ROW Agreement from CP.[255]

ENMAX challenged the validity of the assignment before the Alberta Court of Queen's Bench.[256] The Court of Queen's Bench: (1) held that the assignment of the ROW Agreement was valid and enforceable; (2) confirmed that Remington was entitled to terminate the ROW Agreement pursuant to the terms; and (3) directed ENMAX to file an application with the AUC to relocate the lines. The Alberta Court of Appeal upheld the conclusions of the Court of Queen's Bench, and ENMAX subsequently made an application to the AUC in August 2014 to have the lines removed.[257]

Remington registered as a participant before the AUC but did not submit any evidence. ENMAX's application included six relocation options; however their preferred option was to have the lines re-routed under city streets and over property owned by Alberta Infrastructure, at a cost of approximately $13.3 million.[258] The AUC ultimately concluded that ENMAX's relocation proposal was not in the public interest and denied its application.[259] Remington subsequently sought leave to appeal the decision before the Alberta Court of Appeal.

In its application, Remington alleged that the AUC failed to respect the contractual relationship between the parties; failed to appreciate that ENMAX was trespassing on Remington's lands; that the AUC was incorrect to assume the Surface Rights Board (SRB) had the jurisdiction to grant a right of entry and compensation retroactively; and that the AUC has exceeded its jurisdiction by, in effect, expropriating Remington's lands.[260]

253 *Remington Development Corp v Enmax Power Corp*, 2012 ABCA 196, 66 Alta LR (5th) 92 [*Remington* II], leave to appeal to SCC refused, 34977 (17 January 2013).

254 *Remington Development Corp v Enmax Power Corp*, 2016 ABCA 6, 2016 ABCA 6 (CanLII) [*Remington* III].

255 *Ibid* at para 2.

256 *Remington* I, *supra* note 252.

257 *Remington* II, *supra* note 253.

258 *Remington* III, *supra* note 254 at para 6.

259 *Re Distribution Performance-Based Regulation Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers* (5 February 2015), 3434-D01-2015, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2015/3434-D01-2015.pdf>.

260 *Remington* III, *supra* note 254 at para 14.

b. Decision

The Court of Appeal noted that the applicable standard of review was whether the appeal is prima facie meritorious or frivolous.[261] In reviewing Remington's application the Court noted that the AUC has exclusive jurisdiction over transmission lines in Alberta, and that Remington did not participate or raise any concerns during the AUC hearing process.[262] The Court also noted that the AUC decision explicitly acknowledged that if the lines were to remain, Remington would likely be compensated through the SRB process.

For these reasons, the Court of Appeal held that the AUC's decision was appropriate and affirmed that while the SRB is ancillary to the AUC; both bodies are meant to work together.[263] Therefore, the decision by the AUC to reject ENMAX's application simply had the effect of meaning that Remington and ENMAX have to negotiate an ROW Agreement, or proceed to the SRB for a right of entry order. Ultimately, the Court found the AUC's decision fell within the range of possible acceptable outcomes that are defensible in light of the facts, and rejected Remington's appeal.

The decision of the AUC coupled with the Court of Appeal's decision to deny leave to Remington effectively alters the contractual rights as between the parties, notably the right of either party to terminate the ROW Agreements and require the facilities to be relocated at the expense of the grantee. The decision strongly suggests the AUC will imply a public interest assessment to a ROW Agreement even in those cases where a ROW Agreement contains an express termination right and allocates relocation costs. As land use conflicts are likely to expand as urban fringe areas are increasingly absorbed into municipalities parties seeking to have utility infrastructure relocated to allow development should pay close attention to this decision when considering available options.

2. *PETROGLOBE INC. V. LEMKE*[264]

The *Lemke* decision is just one of a number of decisions released last year relating to land owners trying to recover overdue annual rentals under section 36 of the *Surface Rights Act*.[265] Section 36 of the *SRA* is designed to provide lessors with a means of recovery for surface leases when they remain unpaid by the operator. However, this case was unique because PetroGlobe Inc. (PetroGlobe) entered bankruptcy proceedings. Thus, the SRB focused on the interaction of section 36 of *SRA* and section 69.3 of the *BIA*.[266]

261 *Ibid* at para 10.
262 *Ibid* at para 18.
263 *Ibid* at para 26.
264 2015 ABSRB 740, 2015 ABSRB 740 (CanLII) [*Lemke*].
265 *Surface Rights Act*, RSA 2000 c S-24, s 36 [*SRA*]. Related decisions include: *Portas v PetroGlobe Inc*, 2015 ABSRB 708, 2015 ABSRB 708 (CanLII) [*Portas*]; *Rodin v Petroglobe Inc*, 2015 ABSRB 826, 2015 ABSRB 826 (CanLII); *Rodin v Petrolobe Inc*, 2015 ABSRB 737, 2015 ABSRB 737 (CanLII) [*Rodin*]; *McMann v Petroglobe Inc*, 2015 ABSRB 827, 2015 ABSRB 827 (CanLII); *Labutis v PetroGlobe Inc*, 2015 ABSRB 829, 2015 ABSRB 829 (CanLII); *Sippola v PetroGlobe Inc*, 2015 ABSRB 830, 2015 ABSRB 830 (CanLII).
266 *BIA, supra* note 242, s 69.3.

a. Background

Doug and Marg Lemke (the Lemkes) owned lands on which PetroGlobe Inc. (PetroGlobe) was the Operator of a surface lease. PetroGlobe first defaulted on its annual compensation payment on 24 June 2013. PetroGlobe then made an assignment into bankruptcy on 17 October 2013. Eleven days later the Lemkes made an application under section 36 for compensation. The fact that the Lemkes made their application to the SRB only after PetroGlobe had entered into bankruptcy is important because under section 69.3 of the *BIA* all proceedings against a bankrupt party are stayed. Section 69.3(1) states:

> Subject to subsections (1.1) and (2) and sections 69.4 and 69.5, on the bankruptcy of any debtor, no creditor has any remedy against the debtor or the debtor's property, or shall commence or continue any action, execution or other proceedings, for the recovery of a claim provable in bankruptcy.[267]

Thus, the question for the SRB was whether the stay of proceedings also prevented the SRB from directing the government to make payment under the *SRA*. In other words, whether an action under section 36 of the *SRA* is considered a "proceeding" for the purposes of section 69.3 of the *BIA*.

b. Decision

The Lemkes essentially raised four different arguments. First, they argued the section 36 application was simply between themselves and the government and therefore section 69.3 was not triggered. The SRB found that while this would seem to be true based on the purpose of section 36, section 36 also requires the government to take action against the Operator. The SRB specifically noted that the *SRA* was amended to specifically provide that the Crown would take action against the Operator under section 36. Therefore, any action under section 36 is also necessarily a proceeding against the Operator, and would contravene section 69.3.

The Lemkes' next argument was that the Government itself is not the "creditor" and that the Lemkes were. Therefore, the Lemkes submitted the SRB could take action to terminate the surface lease without interfering with the *BIA*. This submission was rejected with the SRB noting that while this was technically the case, the SRB would still effectively be proceeding on behalf of the creditor and that according to statutory interpretation provisions like this would still contravene the *BIA*.

The third argument relied on the fact that guarantees are exempt under section 69.3 of the *BIA*. Therefore, the Lemkes submitted that the compensation provided under section 36 was essentially meant to be a guarantee to the lessor by the Province for the surface lease, and as such would be exempt. The SRB disagreed, finding that because certain subsections of section 36 give the SRB discretion, it could not be a guarantee.

Finally, the Lemkes argued that lessors should be treated differently under bankruptcy legislation. In making this submission, the Lemkes relied on the *Landlord's Rights on*

[267] *Ibid*.

Bankruptcy Act of Alberta.[268] This argument failed, largely due to the doctrine of paramountcy, and the fact that the Lemkes were claiming compensation that was owed before PetroGlobe entered bankruptcy.[269] Therefore, the SRB found that the stay of proceedings mandated under section 69.3 also applied to proceedings under section 36.

The *Lemke* decision is also interesting in light of the decisions in *Portas*,[270] and *Rodin*.[271] In *Rodin*, the SRB determined that it could direct the Minister to make a payment under section 36 in regards to unpaid rent owed before a company goes bankrupt, if the landowner files a new section 36 application for the unpaid rent after the company is assigned into bankruptcy. In making this decision the SRB held that "[t]he Board has authority to proceed under section 36 for any payments that become due after the assignment into bankruptcy."[272]

The SRB made a similar decision in *Portas*, with the SRB finding that because the section 36 application was made after PetroGlobe entered bankruptcy the issue of whether there was a claim provable in bankruptcy was not engaged.[273] The SRB held that because the section 36 application is in relation to debts accrued after bankruptcy, these debts are not a claim provable in bankruptcy.[274] Together these decisions seem to evidence a pattern whereby claims under section 36 for compensation will be allowed if the claim is made after the Operator has already entered bankruptcy. As a result, it seems a lessor's entitlement to compensation from the SRB may arbitrarily rest on when the lessor makes their application under section 36, before or after the Operator enters bankruptcy.

3. *TOGSTAD V. ALBERTA (SURFACE RIGHTS BOARD)*[275]

a. Background

The AUC had granted AltaLink Management Ltd. (AltaLink) a permit and licence to construct and operate the Western Alberta Transmission Line. The Appellants appealed the SRB's decision granting Altalink a right of entry onto their lands, and appealed the dismissal of their application for judicial review. These two appeals were heard together. In essence, the Appellants' argument was that the SRB does not have the jurisdiction to consider projects that are not "wholly in Alberta."[276]

At the trial level the Court of Queen's Bench held that the SRB "correctly concluded the objection by Mr. Togstad raised a constitutional question which it correctly declined to answer."[277] The Appellants contested that their objection was not constitutional but was based on the statutory limit of the SRB's jurisdiction, and the fact that the SRB was only required to determine the nature of the transmission line as a question of fact.[278]

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268 *Landlord's Rights on Bankruptcy Act*, RSA 2000, c L-5.
269 *Lemke*, *supra* note 264 at para 8.
270 *Supra* note 265.
271 *Supra* note 265.
272 *Ibid* at para 7.
273 *Portas*, *supra* note 265 at para 16.
274 *Ibid*.
275 2015 ABCA 192, 2015 CarswellAlta 1028 (WL Can) [*Togstad*].
276 *Ibid* at para 3.
277 *Ibid* at para 2.
278 *Ibid* at para 3.

b. Decision

On appeal, the Court noted that clearly the Appellants had raised a constitutional question because "[i]t was framed in constitutional terms and accompanied by a *Notice of Constitutional Question.*"[279] The SRB does not have the jurisdiction to consider constitutional questions; therefore, the Court of Appeal affirmed the Court of Queen's Bench holding that the SRB had not erred by declining to consider the Appellant's question.[280]

The Court of Appeal also noted that the Appellants were essentially forum shopping and that their objections were collateral attacks on the AUC's jurisdiction.[281] The SRB was permitted to rely on the AUC's determination when making its decision to grant a right of entry. Further, under the *SRA,* the SRB is "statutorily prohibited from making an order which is inconsistent with the Commission's permit."[282] Thus, the legislative scheme does not support the Appellants' argument and thus the appeals were both dismissed.

VII. WATER ISSUES AND INDUCED SEISMICITY

A. WATER

1. THE BRITISH COLUMBIA ENVIRONMENTAL APPEAL BOARD REVOKES NEXEN'S WATER LICENCE

a. Background

In northeastern British Columbia, Nexen utilized short-term water licences issued by the British Columbia Oil and Gas Commission (OGC) until 11 May 2012 when it obtained a five year licence to divert and store a maximum of 2.5 million cubic litres of water from North Tsea Lake (Licence). North Tsea Lake is within the FNFN's traditional territory. Nexen required access to this water for storage and use in shale gas hydraulic fracturing. The FNFN appealed the issuance of the Licence to the British Columbia Environmental Appeal Board (EAB) on 11 June 2012, on the basis that it was inconsistent with the purposes of British Columbia water legislation, and it was provided based on inadequate data and a flawed design.[283] The FNFN also argued that the Provincial Crown did not discharge its duty to consult.[284]

b. Analysis and Decision

On 3 September 2015, the EAB allowed the FNFN appeal and cancelled Nexen's water licence for North Tsea Lake.[285] In its lengthy decision, the EAB cited two reasons for the revocation: (1) fundamental flaws in the scientific and technical evidence used to obtain the

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279 *Ibid* at para 4.
280 The Court of Queen's Bench decision is *Kure v Alberta (Surface Rights Board)*, 2014 ABQB 572, 26 Alta LR (6th) 212.
281 *Togstad*, *supra* note 275 at para 8.
282 *Ibid* at para 7. See *SRA*, *supra* note 265, s 15.
283 *Gale v Assistant Regional Water Manager* (3 September 2013), 2012-WAT-013(c) at paras 130–37, online: BCEAB <www.eab.gov.bc.ca/water/2012wat013c.pdf> [*Nexen*].
284 *Ibid* at para 379.
285 *Ibid* at para 503.

licence; and (2) failures in the constitutionally-required duty to consult the FNFN on the potential issuance of the licence. The first failure falls on Nexen, while the second issue is the responsibility of the Crown.

i. *Decision on the Technical Merits of the Licence*

The Licence was based on a 2011 revised water plan (the 2011 Plan) prepared by Nexen, reviewed by an external consultant, and evaluated by the Natural Resources Ministry (Ministry). The Licence authorized a maximum annual withdrawal and it also stipulated a minimum flow rate of 0.351m^3 per second based on the 2011 Plan. Nexen was required to immediately stop withdrawals if the flow rate fell beneath the minimum. After the FNFN appeal was filed, drought conditions forced the OGC to issue a directive suspending withdrawals from most rivers and lakes in northeastern British Columbia. Nexen continued to withdraw in breach of the minimum flow rates stipulated in the Licence. Consequently, the Ministry attached additional safety and monitoring conditions to the Licence.

The EAB held that the withdrawal scheme built into the Licence was "not supported by scientific precedent, appropriate modeling, or adequate field data."[286] The EAB found that the Ministry's conclusion that the Licence would pose no significant effects on the environment was founded on "incorrect, inadequate, and mistaken factual information and modelling results."[287] Where there is a lack of baseline data, the Ministry will face an increased obligation for more extensive investigation.

ii. *Decision on First Nations Consultation*

Nexen, the Ministry, and the FNFN engaged in communications regarding the Licence from April 2009 until the issuance of the Licence in May 2012.[288] The decision sets out an extensive review of the relevant communications. The Ministry sent a letter requesting the FNFN's consideration of the Ministry's findings on adverse effects of the Licence in January 2012. After some confusion, ultimately the FNFN did not reply and the Ministry issued the Licence without further consultation with the FNFN.

The EAB determined that the level of consultation required in this instance fell in the mid-range of the spectrum from *Haida Nation v. British Columbia (Minister of Forests)*.[289] While the consultation process must be flexible, the EAB held that it must also be transparent and provide parties with clarity as to each other's needs and expectations.[290] The EAB critiqued the lack of initial communications from the Ministry outlining the intended process and found that the Ministry failed to provide clarity as to Nexen's role in the consultation. As there was no formal delegation, Nexen's active role may have been viewed as purely in self-interest.[291]

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286 *Ibid* at para 337.
287 *Ibid* at para 338.
288 *Ibid* at paras 333–86.
289 2004 SCC 73, [2004] 3 SCR 511; *Nexen, supra* note 283 at para 440.
290 *Nexen*, *ibid* at para 441.
291 *Ibid* at para 447.

The EAB reiterated that consultation must always occur in good faith. The fundamental failure of the Ministry to consult in good faith was evidenced by internal emails that the Ministry intended to issue the Licence, notwithstanding all the unknowns.[292] The emails demonstrated a great inconsistency between internal correspondence and discussions with the FNFN — making it clear that the Ministry did not consult in good faith.

c. Remedy

Given the seriousness of the technical and scientific flaws in the materials earning the Licence and the serious flaws in the consultation process, the EAB deemed that cancellation of the Licence was appropriate in the circumstances. The Licence was "fundamentally flawed in concept and operation."[293] The EAB acknowledged the prejudice that would result to Nexen, but prejudice was lessened upon consideration that Nexen had enjoyed over half of the Licence term.

2. LAND USE PLANNING IN THE PEEL WATERSHED, YUKON

On 4 November 2015, the Yukon Court of Appeal allowed the Government of Yukon's appeal from a decision of the Yukon Supreme Court (YKSC) — but only to send the parties back to an earlier stage in the land use planning process than ordered by the lower court.[294] In the Peel Watershed decision, the Yukon Court of Appeal focused on the ability of the Yukon government to propose general amendments to a Regional Land Use Planning Commission's (Planning Commission) recommended plan, and then subsequently make drastic amendments at the final stage in the land use planning process, after consultation is complete.

a. Background

The *Peel Watershed* case centres on the judicial interpretation of the land use planning procedure set out in the Umbrella Final Agreement between Yukon, Yukon First Nations, and Canada. The process involves six different steps.[295] First, a Planning Commission will submit a recommended plan to the Yukon government. The Government will then consult with affected Yukon First Nations. The Government will then either accept the plan or provide written reasons for rejection or proposed modifications. Next, the particular Planning Commission will reconsider the plan and will submit a final recommended plan. The Government then consults with affected First Nations on the final recommended plan. In the final step of the process, the Government will accept, reject, or modify what will become the final plan.

In this case, the final regional land use plan for the Peel Watershed, announced by the Yukon government on 21 January 2014, was very different from the final recommended plan put forward by the Peel Watershed Planning Commission — the plan changed from 80

292 *Ibid* at paras 474–76.
293 *Ibid* at para 337.
294 *The First Nation of Nacho Nyak Dun v Yukon*, 2015 YKCA 18, [2016]1 CNLR 73 [*Peel Watershed* CA], rev'g 2014 YKSC 69, [2015] 1 CNLR 81 [*Peel Watershed*], leave to appeal to SCC granted, 2016 Carswell Yukon 59 [*Peel Watershed* SCC].
295 *Peel Watershed*, *ibid* at paras 158–62.

percent protected land and 20 percent open for mineral exploration to 71 percent open for mineral exploration and 29 percent protected.[296]

b. Analysis and Decision

The YKSC emphasized the importance of a broad, generous, and purposive interpretation of obligations owed by the Crown to the First Nations. The YKSC agreed with the plaintiffs and held that the Yukon government's interpretation of its ultimate power over land use planning decisions was "an ungenerous interpretation not consistent with the honour and integrity of the Crown."[297] The Yukon Court of Appeal agreed with the YKSC's broad approach to interpretation. Allowing the Yukon government's interpretation would undermine the purpose of the process in the Umbrella Final Agreements because "the Consultations with First Nations would effectively be meaningless and the work of the Commission would effectively serve no purpose, if Yukon could make any changes it liked" in the final stage.[298]

The Court of Appeal determined it was not appropriate to simply arbitrarily resume the process to allow the Yukon government to submit its version of the plan as "modifications" for the commission to review. Instead, the Court of Appeal ordered that the process was to recommence at the final First Nations consultation stage and any modifications introduced by the Yukon government must conform to its initial written reasons to the Peel Watershed Planning Commission at an earlier stage.

The Court of Appeal held that the Yukon government had erroneously departed from the land use planning process by establishing a significantly different final plan for the Peel Watershed in the last stage, after consultation. While it confirmed the Yukon government's arguments that it has the final decision-making power over land use planning, it rejected the assertion that its power it "entirely unconstrained."[299] The Court of Appeal found that the Yukon government must exercise its ability to propose modifications at the appropriate stage in the process — a stage that allows for consultation with affected First Nations. The appeal was allowed to the extent of sending the plan back to the initial consultation stage where the Yukon Government failed to provide detailed explanations of its proposed modifications.

On 23 December 2015, the First Nation of Nacho Nyak Dun, the Tr'ondëk Hwëch'in and Vuntut Gwitchin First Nations, and two environmental organizations filed for leave to appeal to the Supreme Court of Canada. On 9 June 2016, the Supreme Court granted leave to appeal from the Yukon Court of Appeal decision.[300]

3. BRITISH COLUMBIA'S NEW WATER LEGISLATION

British Columbia began an extensive project of modernizing its provincial water laws in 2009 involving significant public and stakeholder engagement. British Columbia's *Water Act*

296 *Ibid* at para 111.
297 *Ibid* at para 182.
298 *Peel Watershed* CA, *supra* note 294 at para 93.
299 *Ibid* at paras 105, 119.
300 *Peel Watershed* SCC, *supra* note 294.

(now known as *Water Users' Communities Act*) has remained largely unchanged since it was enacted in 1909, and the Province is long overdue for modernization in line with current scientific knowledge and environmental principles.[301] The resulting *Water Sustainability Act* and an initial set of regulations came into force on 29 February 2016.[302]

Until the introduction of the *Water Sustainability Act*, British Columbia was the sole Canadian province operating without groundwater licensing. Now, entities requiring groundwater for non-domestic uses like irrigation or hydraulic fracturing will be required to apply for a licence subject to fees and annual rentals — bringing groundwater on par with existing surface water regimes. Domestic purposes are limited to household use such as drinking water, food preparation, and small-scale garden irrigation.[303] The regulations contemplate a three year transitional period for licence application but have a built-in incentive, waiving application fees for parties applying before 1 March 2017.[304]

Another change is the introduction of provisions allowing for review of licences issued for unlimited terms. Section 23 of the *Water Sustainability Act* allows decision-makers to review the terms and conditions of a licence every 30 years. The decision-maker is empowered to amend the licence based on a broad list of factors including: changes in technology and best practices of water efficiency and conservation, the licensee's beneficial use of the water, and the effects of climate change.[305] Additionally, all licences will be subject to a particular "Water Sustainability Plan," under which the Lieutenant Governor in Council can make regulations directing the water manager to amend the terms and conditions of licences under a particular plan. This provision will allow for changes to maximum quantities of water diversion, or even licence cancellation, if regulations to that effect are introduced.

The Government has opted for a "phased approach" with respect to the development of linked policies and regulations.[306] Interested parties can expect progress on the next phase of regulations, focusing on measuring and reporting, livestock watering, water objectives, planning and governance, later in 2016.[307]

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301 *Water Users' Communities Act*, RSBC 1996, c 483. Only a handful of amendments have been introduced: Environmental protections in 1960 and drinking water quality provisions in 2004.

302 *Water Sustainability Act*, SBC 2014, c 15 [*WSA*]; *Water Sustainability Regulation*, BC Reg 36/2016 [*WSR*]; *Water Sustainability Fees, Rentals and Charges Tariff Regulation*, BC Reg 37/2016; *Groundwater Protection Regulation*, BC Reg 39/2016; *Dam Safety Regulation*, BC Reg 40/2016; *Water District Regulation*, BC Reg 38/2016.

303 *WSA*, *ibid*, s 2.

304 *WSR*, *supra* note 302, s 55.

305 *WSA*, *supra* note 302, s 23.

306 Government of British Columbia, "Water Sustainability Act," online: <https://engage.gov.bc.ca/water sustainabilityact/>.

307 *Ibid*.

B. INDUCED SEISMICITY

1. BRITISH COLUMBIA

a. Amendments to British Columbia's *Drilling and Production Regulation*: Seismic Reporting

On 30 July 2015, British Columbia amended the *Drilling and Production Regulation* to include reporting requirements related to seismic events.[308] This amendment comes after two induced seismicity studies concluded that seismic activity in both the Horn River Basin and Montney Trend areas resulted from hydraulic fracturing activities. Under the new section 21.1 of the *Drilling and Production Regulation*, permit holders engaged in fracturing or disposal operations must immediately report seismic events within a 3 kilometre radius of the drilling pad to the OGC.[309] The section stipulates that reporting is only required where the seismic event is greater than a 4.0 magnitude or it produces a ground motion felt by an individual within the radius. If the well responsible for a magnitude of 4.0 or greater can be identified, the permit holder is required to suspend operations immediately. The suspension will end when the permit holder has implemented any necessary operational changes approved by the OGC to reduce the likelihood of future events.

Before this amendment, the *Drilling and Production Regulation* did not require all permit holders to report on seismic events although it was required as a condition of some permits. Depending on the nature and frequency of operations, the reporting obligation could become somewhat onerous for permit holders, as a report to the OGC is required where *any* individual within a three kilometre radius felt a ground motion during operations.

2. ALBERTA

a. Subsurface Order No. 2

Since the 1960s, Alberta energy development has been linked to numerous subsurface seismic events. During operations from 2013 to 2015, the AER discerned "persistent patterns of seismic events above background levels west of the community of Fox Creek, Alberta."[310] The timing of the events indicated that a link to multi-stage hydraulic fracturing in the Duvernay Zone may exist. After two events of magnitudes greater than 4.0 in January 2015 the AER determined an order was necessary to ensure responsible development and public safety.

On 19 February 2015, the AER issued Subsurface Order No. 2, (the Order) concerning both seismic monitoring and reporting. The Order, issued under section 11.104 of the *Oil and Gas Conservation Rules*, affects all hydraulic fracturing operations in the Fox Creek area of the Duvernay Zone. Before commencing operations with respect to such pool, the licensee

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308 BC Reg 282/2010.

309 *Ibid*, s 21.1.

310 Alberta Energy Regulator, "Subsurface Order No. 2: Monitoring and Reporting of Seismicity in the Vicinity of Hydralic Fracturing Operations in the Duvernay Zone, Fox Creek, Alberta," Bulletin 2015-07 (Calgary: AER, 19 February 2015), online: <https://www.aer.ca/rules-and-regulations/bulletins/Bulletin-2015-07.pdf>.

must assess the potential of induced seismicity and establish a response plan. Licensees are required to use seismic monitoring equipment capable of detecting a 2.0 magnitude seismic event within five kilometres and report any such event to the AER immediately while invoking the response plan. If a seismic event greater than a 4.0 magnitude is detected within five kilometres of the licensed well, the licensee must immediately report the event to the AER and cease operations. Written consent to the licensee's resumption of operations by the AER is required in order to lift the suspension. All seismic events greater than 4.0 magnitude will be posted on the AER Compliance Dashboard.

On 13 June 2015, the AER recorded a 4.3 magnitude seismic event near the Fox Creek area. Chevron Canada reported a 3.6 magnitude event the same day and suspended operations. The AER reviewed Chevron Canada's response, and on 29 June 2015, the AER notified Chevron Canada that it was approved to resume hydraulic fracturing operations based on the corporation's submitted response plan for modified operations. The AER ordered that Chevron Canada compare its recordings to future events reported through Natural Resources Canada, in light of the potential inaccuracy of the corporation's seismic monitoring systems.

On 12 January 2016, Repsol Oil & Gas Inc. (Repsol) reported a 4.8 magnitude seismic event — the largest earthquake in the Fox Creek area in over a year. Individuals on-site felt the event and unconfirmed reports indicate the event may have been felt up to 32 kilometres east of the operation.[311] In compliance with the order, Repsol ceased hydraulic fracturing operations immediately. On 24 March 2016 Repsol submitted a flow back plan aimed at eliminating or reducing future induced seismicity to acceptable magnitudes. The AER issued a Resumption of Hydraulic Fracturing Operations notice to Repsol on 4 April 2016, approving the company's mitigation plan and allowing the recommencement of operations subject to notice and meeting with the AER to discuss the event.

b. Fox Creek Induced Seismicity Study

Beginning in December 2013, monitoring by the AER revealed clusters of low-magnitude seismic events in the area surrounding Fox Creek, paired with several greater than 4.0 magnitude events. As a result, the AER announced in early 2016 that it intends to devote resources to studying the link between hydraulic fracturing and seismicity.[312] The project objectives include: studying the area's seismicity in order to provide the public and decision-makers with information; surveying the subsurface geological environment where seismic events are occurring; analyzing local operations and potential triggers; and developing theories as to causation. The AER has not yet publicized results from the study.

311 Alberta Energy Regulator, "Compliance Dashboard," Reference No IS101 (12 January 2016), online: <www1.aer.ca/compliancedashboard/incidents.html>.

312 Alberta Energy Regulator & Alberta Geological Survey, "Introduction to the Induced Seismicity Study in the Fox Creek Area: Presentation to the Fox Creek Town Council" (25 January 2016), online: <www.foxcreek.ca/ieadmin/files/aer_presentation.pdf>.

VIII. OTHER NOTABLE DEVELOPMENTS OF INTEREST

A. *EXTRACTIVE SECTOR TRANSPARENCY MEASURES ACT*

The *Extractive Sector Transparency Measures Act* is a federal initiative legislating Canada's commitment to targeting international corruption.[313] The Act establishes reporting obligations for entities engaged in the commercial development of oil, gas, or minerals anywhere in the world. *ESTMA* came into force 1 June 2015 and will affect financial year-ends commencing after 1 June 2015. The obligation to report payments to Canadian Aboriginal governments will not come into force until 1 June 2017. Natural Resources Canada oversees implementation and enforcement and has issued a guidance document for concerned parties, as well as a document outlining the technical reporting specifications.[314]

The broadness of the legislation could impact a significant number of industry parties, whether in oil, gas, or mining. The definition of "entity" in *ESTMA* is broad and includes business organizations that control a corporation, trust, partnership, or similar.[315] Similarly, the definition of "commercial development" includes exploration and extraction of oil, gas, and minerals, as well as holding related licences or permits.[316] In order to be subject to the reporting requirements, an entity must have a connection to Canada. A connection is not necessarily substantial, allowing for *ESTMA* to cast a potentially wide net. For example, if the entity is listed on the Canadian Stock Exchange, it will be subject to the reporting requirements.[317] Additionally, an entity will be subject to *ESTMA* where it has a place of business in, does business in, or has assets in Canada, and either employs an average of 250 people globally, has $20 million in global assets, or has $40 million in global consolidated revenues.[318] It should be noted that the asset and revenue criterion is not limited to assets or revenue related to oil, gas, or minerals.

ESTMA aims to both decrease corruption and increase transparency, with reporting entities required to make the report and related prescribed information available to the public for at least five years. Reporting entities must publish their reports on the internet and provide Natural Resources Canada with a direct link to the report within 150 days following the end of the entity's financial year.[319] *ESTMA* reports will include payments to not only government-related authorities and individuals, but also payments made to third parties having received the payment on a payee's behalf.[320] The threshold is an aggregate of $100,000 annually in a particular category such as taxes, royalties, or bonuses.[321]

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313 SC 2014, c 39 [*ESTMA*].

314 See Government of Canada, *Extractive Sector Transparency Measures Act: Guidance* (Ottawa: Natural Resources Canada, 2016), online: <www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/mining-materials/PDF/ESTMA-Guidance_e.pdf>; Government of Canada, *Extractive Sector Transparency Measures Act: Technical Reporting Specifications* (Ottawa: Natural Resources Canada, 2016), online: <www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/mining-materials/PDF/ESTMA-Technical_e.pdf> [*Technical Reporting Specifications*].

315 *ESTMA, supra* note 313, s 2.

316 *Ibid*.

317 *Ibid*, s 8 (1)(a).

318 *Ibid*, s 8. Section 8(1)(b) only applies to entities meeting at least 2/3 of the size-related criteria in the past two financial year.

319 *Technical Reporting Specifications*, *supra* note 314.

320 *ESTMA, supra* note 313, s 3.

321 *Ibid*, s 2.

The legislated maximum fines have the potential to be very punitive at $250,000 per offence per day.[322] Offences include failure to properly report or to make the report publicly available, providing false or misleading information, and failure to comply with an order. Directors and officers will be open to liability if they directed, authorized, assented to, acquiesced in, or participated in the offence but have access to a due diligence defence.[323]

B. SUPREME COURT OF CANADA GRANTS LEAVE AND HEARS APPEAL AGAINST THE ALBERTA ENERGY REGULATOR

On 30 April 2015, the Supreme Court of Canada granted leave to appeal to Jessica Ernst (Appellant), as to her constitutional claim against the AER's predecessor, Alberta Energy Resources Conservation Board and Alberta Environment and Sustainable Resource Development (Regulator).[324] The central question to be decided by the Supreme Court of Canada is whether the general statutory immunity clause in section 43 of the *Energy Resources Conservation Act*[325] (Statutory Immunity Clause) is inoperative or inapplicable to the extent that it operates to bar a claim for the Regulator's breach of the plaintiff's constitutional rights to freedom of expression. The *Ernst* appeal will be a constitutional test case allowing the Supreme Court of Canada to weigh in on whether a legislature can shield its regulatory bodies from the application of the *Canadian Charter of Rights and Freedoms*.[326]

1. BACKGROUND

The Appellant, who owns property near Rosebud, Alberta, has alleged a link between the contaminated and flammable state of the water from her private well and EnCana Corporation's hydraulic fracturing activities in the vicinity. The Appellant has been outspoken and critical throughout the regulatory proceedings with the Regulator, often went to the media to tell her story, and takes serious issue with the Regulator's approach to her claims. She further alleges that the Regulator's Compliance Branch refused to accept the Appellant's further communications unless she ceased media and public statements.

2. DECISIONS BELOW

The Appellant brought claims against EnCana Corporation for the torts of negligence and nuisance. She also sued the Regulator for breaching her rights to free speech under section 2(b) of the *Charter* (*Charter* Claim) and for "negligent administration of a regulatory regime."[327] The claims against EnCana Corporation are continuing before the ABQB, but Chief Justice Wittman struck the claims against the Regulator.[328] The Chief Justice found the negligence claim against the Regulator to be unsupportable at law. Though the *Charter*

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322 *Ibid*, s 24.
323 *Ibid*, ss 25–26.
324 *Ernst v EnCana Corp*, 2013 ABQB 537, [2013] WWR 738 [*Ernst* QB], aff'd 2014 ABCA 285, [2014] WWR 496 [*Ernst* CA], leave to appeal to SCC granted, [2015] 2 SCR vi [*Ernst* Leave].
325 *Energy Resources Conservation Act*, RSA 2000, c E-10, s 43 [*ERCA*] (which was repealed and replaced by the *REDA, supra* note 224, which contains a similar immunity clause in section 27).
326 Part I of the *Constitution Act, 1982*, being Schedule B to the *Canada Act 1982* (UK), 1982, c 11 [*Charter*].
327 *Ernst* CA, *supra* note 324 at para 2.
328 *Ernst* QB, *supra* note 324.

Claim was not so unsustainable that it could be struck, he held that the Statutory Immunity Clause barred both claims.

The Statutory Immunity Clause read as follows:

Protection from action

43 No action or proceeding may be brought against the Board or a member of the Board or a person referred to in section 10 or 17(1) in respect of any act or thing done purportedly in pursuance of this Act, or any Act that the Board administers, the regulations under any of those Acts or a decision, order or direction of the Board.[329]

This section was subsequently repealed. Section 27 of the *REDA* replaces the prior Statutory Immunity Clause, containing very similar language.[330]

The Alberta Court of Appeal agreed with the Court of Queen's Bench and the Regulator that the general Statutory Immunity Clause is a constitutionally legitimate restriction on an individual claiming damages under section 2(b) of the *Charter*.[331] The Appellant argued that the Statutory Immunity Clause is inapplicable due to sections 24(1) and 52(1) of the *Charter*. Section 24(1) provides individuals with a remedy for breach that is "just and appropriate in the circumstances" and section 52(1) embodies constitutional supremacy, rendering inconsistent legislation of no force or effect. However, the Court pointed to a number of instances where legitimate provisions may limit an individual's access to a constitutional remedy — such as a statute of limitations.

3. SUPREME COURT OF CANADA RESERVES ITS DECISION

If the Supreme Court of Canada were to agree with the courts below, the Appellant argues that "[t]he remedy section of the *Charter* would be gutted [because] … a provincial government, as one of the very institutions that the *Charter* seeks to control, could declare itself or its agencies immune."[332] The Supreme Court of Canada reserved its judgment on 12 January 2016. We eagerly await the release of its decision on an issue that could have widespread effects on the constitutionality of federal and provincial statutory immunity clauses.

C. ALBERTA ENERGY REGULATOR

1. LISTENING, LEARNING, LEADING: A FRAMEWORK FOR REGULATORY EXCELLENCE

The AER released a guiding document from its initiative with the University of Pennsylvania's Penn Program on Regulation (Penn Program) in September 2015. The AER commissioned the Penn Program to consult on the AER's "Best-in-Class Project" to deliver

329 *ERCA*, *supra* note 325, s 43.
330 *REDA, supra* note 224.
331 *Ernst* CA, *supra* note 324 at para 30.
332 *Ernst* Leave, *supra* note 324 (Factum of the Appellant at para 4).

"'protective, effective, efficient, and credible' regulatory performance."[333] The final report, *Listening, Learning, Leading*, is the culmination of four major dialogue sessions with over 150 participants, 60 interviews of interested parties, and studies of the current AER structure and mandate. The Report concludes that the core attributes of regulatory excellence are: (1) utmost integrity; (2) empathic engagement; and (3) stellar competence.[334] Further, the Report covers nine tenets that bolster the three core elements, including fidelity to law, commitment to public interest, responsiveness, and analytical capacity.[335] The Report outlines a framework for the AER to implement, discusses hurdles to excellence, and details performance indicators.

2. COMPLIANCE DASHBOARD

To increase transparency of the AER's activities and public access to information, the AER introduced Compliance Dashboard in late February 2015. The Dashboard replaces previous incident reporting and monthly summary programs. It provides the public access to information publicly accessible under the *Freedom of Information and Protection of Privacy Act* in an easily accessible, searchable, and readable format.[336] The Dashboard includes information on incidents and investigations, as well as compliance activities and enforcement actions since July 2014. It also highlights non-compliances if there is a potential risk to public safety, the environment, or resource conservation.

3. PUBLICATION OF PROCEDURAL DECISIONS

On 23 September 2015, the AER released Bulletin 2015-28.[337] Effective immediately, the AER implemented an initiative that embodies both increased transparency and access to information by publishing both substantive procedural and participation (standing) decisions on its website. The publication includes decisions made by hearing panels as well as other AER decision-makers. Lawyers and other parties involved in AER proceedings will now have the ability to review similar applications — providing potential understanding of the AER's approach to particular issues. In terms of transparency, the AER still has a ways to go as this publication initiative is limited specifically to these two types of decisions: participation and procedural. Statements of concern and related documents are only available through information requests submitted to the AER.

4. INTEGRATED COMPLIANCE ASSURANCE FRAMEWORK

On 12 February 2016 the AER implemented the new compliance assurance framework which rescinds "Directive 019: Compliance Assurance" but does not change or impact the statutory requirements currently in place.[338] The Compliance and Enforcement Program

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333 Cary Coglianese, *Listening, Learning, Leading: A Framework for Regulatory Excellence* (Philadelphia: Penn Program on Regulation, 2015) at i, online: <https://www.aer.ca/documents/about-us/UPenn_Final_Report_Regulatory_Excellence.pdf>.

334 *Ibid* at ii.

335 *Ibid* at iii.

336 RSA 2000, c F-25.

337 Alberta Energy Regulator, "Posting of Participation and Procedural Decisions," Bulletin 2015-18 (Calgary: AER, 23 September 2015), online: <www.aer.ca/documents/bulletins/Bulletin-2015-28.pdf>.

338 Alberta, Energy Resources Conservation Board, "Compliance Assurance," Directive 019 (Calgary: ERCB, 1 September 2010), online: <www.aer.ca/documents/directives/Directive019.pdf>.

Manual is to apply to all AER compliance activities to ensure consistency and transparency in licensee compliance and in enforcement responses. One of the most significant changes is that while there will still be predetermined risk assessment, such assessment will only be used to allocate AER resources and does not equate to a predetermined enforcement response. As such, once the noncompliance has been identified (other than through voluntary self disclosure (VSD)), a notice of noncompliance is provided but an enforcement process will only be utilized if there is a failure to comply with such notice. Each notice of noncompliance forms part of the licensee's compliance history. Any VSD is considered notice of "non-compliance" and is treated similarly. Adding to the consistency in response, the AER has added a triage process for all events of non-compliance to ensure whether, based on five assessment criteria, the event should be referred to an investigation. Such investigation will be subject to standardized procedure and process and if there is the need for enforcement action on behalf of the AER, there will be both an enforcement direction meeting (internal process) and a procedural fairness meeting with the licensee (external process) to ensure consistency, fairness, transparency, and informed decision making.

D. ROYALTY REVIEW

In August 2015, the Government of Alberta commissioned a review of Alberta's oil and gas royalty framework. The Royalty Review Advisory Panel released its report *Alberta at a Crossroads* (the Royalty Report),[339] and on 29 January 2016, the Alberta government held a press conference confirming that it intends to adopt the resulting recommendations. Premier Rachel Notley stated that the current royalty rates are appropriate but the Government intends to "adopt a new framework for assessing deductible costs with greater transparency, accountability and certainty."[340] This will include public disclosure of all costs entities are allowed to deduct when calculating royalty payments. The oil sands royalty rates will remain largely the same, incorporating increased transparency through annual publication of royalty-related financial summaries by project.[341] The modernized royalty framework adopted for crude oil, liquids, and natural gas will create a harmonized "revenue minus costs" approach and imports a flat 5 percent royalty rate for the initial period determined by revenue which could encourage investment when oil prices are low.[342] The new framework will apply to new wells only. The Royalty Report also emphasizes the need to diversify Alberta's economy by creating new opportunities to enhance value-added processing for both gas and bitumen.[343] The new royalty framework is not a complete overhaul of the previous structure. The changes centre on increasing transparency and accountability, spurring innovation and investment, and encouraging responsible resource development.

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339 Royalty Review Advisory Panel, *Alberta at a Crossroads: Royalty Review Advisory Panel Report*, Co (Edmonton: Alberta Energy, 2015), online: <www.energy.alberta.ca/Org/pdfs/RoyaltyReportJan2016.pdf> [*Crossroads*].

340 Government of Alberta, News Release, "Alberta's New Royalty Framework Speech" (29 January 2016), online: <www.alberta.ca/release.cfm?xID=401538F1E58AB-B873-40B1-E9C9A284B7AF4D22>.

341 *Crossroads*, *supra* note 339 at 65–67.

342 *Ibid* at 57.

343 *Ibid* at 67.

E. PETROCHEMICAL DIVERSIFICATION PROGRAM

The Alberta Royalty Review Panel further discussed the need for an increased focus on the value-added sector of oil and gas, including upgrading products like methane and propane. On 1 February 2016, the Alberta government announced a plan to encourage corporations to construct petrochemical plants in Alberta.[344] The Petrochemical Diversification Program will issue up to $500 million in royalty credits to approved proponents. These credits can then be monetized through commercial arrangements with a royalty payor. The application period began 4 February 2016 and ended 22 April 2016. At the time of writing, Alberta had not yet issued a final date for program approvals. However, Alberta Energy indicated that decisions would be made in 2016 as soon as possible after the close of the application deadline.[345]

IX. UTILITY REGULATION AND POWER MARKETS

Three important utility regulation decisions were issued in September 2015. First, the Alberta Court of Appeal released its decision in *Fortis Alberta Inc. v. Alberta (Utilities Commission)*;[346] then the Supreme Court of Canada issued its judgments in two cases heard together — *Ontario (Energy Board) v. Ontario Power Generation Inc.*[347] and *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*.[348]

A. UTILITY ASSET DISPOSITION

1. *FORTIS ALBERTA V. ALBERTA (UTILITIES COMMISSION)*

In *Fortis*, five electric and two gas utilities appealed two decisions of the AUC, with the focus of the appeal on the AUC's 2013 Utilities Asset Disposition Decision (UAD Decision). The AUC intended that the generic UAD Decision would aid in establishing a regulatory approach to utility asset disposition in varying circumstances in light of the decision of the Supreme Court of Canada in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*.[349] *Stores Block* was a significant decision of fundamental importance to the utility industry and consumers as it overruled decades of regulator or regulatory decisions by finding that customers do not share in the gains resulting from dispositions of utility assets in the rate base that are not being used or useful to service. In its UAD Decision, the AUC set out 19 propositions of law established by the *Stores Block* jurisprudence.[350]

In *Fortis*, the Court of Appeal confirmed that the Supreme Court's decision in *Stores Block* and the subsequent line of Court of Appeal cases are still good law in Alberta. The

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344 Government of Alberta, Press Release, "Alberta Takes Significant Step Toward Diversifying Economy" (1 February 2016), online: <www.alberta.ca/release.cfm?xID=401612BEB9080-C4D9-B4D5-F7DD7DFD99A7D80C>.

345 Alberta Energy, "Petrochemical Diversification Program Application Archive: General Questions," online: <www.energy.alberta.ca/EnergyProcessing/4209.asp>.

346 2015 ABCA 295, 389 DLR (4th) 1 [*Fortis*], leave to appeal to SCC refused, 36728 (21 April 2016) [*Fortis* Leave].

347 2015 SCC 44, [2015] 3 SCR 147 [*OPG Decision*].

348 2015 SCC 45, [2015] 3 SCR 219 [*ATCO*].

349 2006 SCC 4, [2006] 1 SCR 140 [*Stores Block*].

350 Set out in *Fortis*, *supra* note 346 at para 107.

Court of Appeal then reviewed the AUC's application of *Stores Block* to stranded assets removed from a utility's rate base. Stranded assets are utility assets that are no longer useful for utility service and have not been operating long enough to be fully depreciated. The UAD Decision focuses on assets lost to unforeseen events like natural disasters or obsolescence outside of the ordinary life span of an asset.

The AUC held that stranded assets should not be included in a gas or electric utility's rate base, with the utility (and not consumers) being responsible to carry the cost of any remaining depreciation. Assets that are no longer utilized to provide services must be removed from the rate base. The outcome is grounded in the position that a utility is in a better position than its customers to protect against extraordinary and unforeseen events. The AUC rejected the electric utilities' argument that *Stores Block* jurisprudence applies only to gas utilities, which are subject to different legislation and a different historical development in Alberta. The Court of Appeal held that the electric utilities' interpretation of the legislation as providing a "guarantee prudent cost recovery model" was a permissible interpretation, but it was not the *only* permissible interpretation. The legislation does not provide electric utilities with a guarantee of recovery of prudent costs, but instead provides the AUC with discretion to make a determination within its larger mandate.

The Court of Appeal was careful to clarify that the AUC's mandate is to provide utilities with a reasonable opportunity to recover prudently incurred costs, but the approach or methodology is within the AUC's discretion. The AUC retains the ability to fulfill this mandate differently on a case-by-case basis. Despite this discretion and flexibility, the principles from *Stores Block* suggest that the risk of stranded assets removed from the rate base will typically fall on the utilities' shareholders, not the consumers.

The legislature has given the AUC a policy role, which includes a mandate of establishing a "balanced and predictable application of principles to the relationship between revenues, expenses and assets (both depreciable and non-depreciable) of utilities on the one hand, and the reasonable expectations of the ratepayers who receive and pay for services on the other."[351] The Alberta Court of Appeal upheld the AUC's policy choices laid out in the UAD Decision as reasonable and dismissed the utilities' appeal.[352]

On 21 April 2016 the Supreme Court of Canada dismissed the application for leave to appeal by ENMAX, Altalink LP, and EPCOR Distribution & Transmission Inc. without reasons.[353] Concurrently, the Court granted an extension of time to serve the application for leave to appeal to Altagas Utilities Inc., ATCO Gas and Pipelines Ltd., ATCO Electric Ltd., and FortisAlberta Inc. These parties have filed applications seeking leave; however, the applications have not yet been heard.

B. PRUDENCE AND RATEMAKING

Both Supreme Court of Canada decisions address the issue of when and to what extent a utility is able to recover its costs under provincial utility regulation. The decisions are Alberta

351 *Ibid* at para 171.
352 *Ibid* at paras 149, 173.
353 *Fortis* Leave, *supra* note 346.

and Ontario appeals from the respective regulatory tribunals and therefore, when read together, can be used to compare and contrast provincial utility legislation. The Supreme Court of Canada considered the meaning of prudence, the discretion of a regulator to apply the "prudent investment test," and the factors that a regulator can consider when making a decision. The predominant theme of the two cases when read together underlines the flexibility and discretion left to utility regulators in ratemaking and in assessing the prudency of utility expenses.

1. *ONTARIO (ENERGY BOARD) V. ONTARIO POWER GENERATION*

a. Regulatory Framework and Brief Facts

The OEB has the statutory power to approve or disallow costs that a utility incurs. Utilities apply to the OEB, and if successful, the costs are incorporated into the utility rates, allowing the utility to recover the expense. In this case, OPG applied for expenses to be covered when it applied for its 2011-2012 operating period rates. The OEB denied coverage of $145 million of the $6.9 billion proposed budget. The disallowed costs related to labour compensation for OPG's nuclear power generation operations. The OEB determined that the OPG costs were disproportionately high compared to similar entities.

OPG appealed on the basis that the OEB's decision was unreasonable. The Ontario Divisional Court dismissed OPG's appeal. The Ontario Court of Appeal allowed the appeal, remitting the matter back to the OEB for redetermination in light of the Divisional Court's reasons. The OEB appealed to the Supreme Court of Canada where the Court (with Justice Abella dissenting) found the Board was not unreasonable in disallowing the costs.

At the Supreme Court, OPG argued that the OEB is "legally required to compensate OPG for all of its prudently committed or incurred costs."[354] The OPG asserted that the Board must make its decision using the "prudence test" without the benefit of hindsight and subject to a presumption of prudence. In contrast, the OEB pointed to the legislation to argue that there is no requirement for it to import a particular methodology to inquire into the prudence of the utility's expenses. An additional issue raised was whether the distinction between forecast and committed costs required different applications of the prudence test.

b. Standing of a Regulatory Tribunal

The OPG argued that the OEB overstepped its regulatory tribunal role by pursuing an appeal from its own decision. The Supreme Court of Canada disagreed and confirmed that the OEB has a statutory right to be heard on judicial appeal. Despite previous jurisprudence limiting the extent to which a tribunal can participate in an appeal of its own decision, the Supreme Court reiterated that a discretionary approach is warranted to find the best balance of impartiality and a fully informed adjudication of the issues. The deciding court should consider whether: the hearing would be otherwise unopposed; existing alternate parties possess the requisite expertise to fully inform the court, and the tribunal plays an adjudicatory role or acts more within a policy-making role. When arguing on appeal, a

[354] *OPG Decision*, *supra* note 347 at para 3.

tribunal can raise arguments that interpret or were implicit in the original decision. However, a regulatory body does not have unfettered range to introduce novel arguments on appeal.

Here, the OEB was the only respondent party to the action that could defend the case. Further, the Supreme Court of Canada found that the OEB was acting under its broad mandate of ensuring just and reasonable utility rates versus adjudicating a multi-party conflict. The Supreme Court rejected OPG's arguments that the Board's standing and arguments were impermissible.

c. Decision

The Supreme Court of Canada found that the Ontario regulations provide the OEB with "broad latitude to determine the methodology it uses in assessing utility costs, subject to the Board's ultimate duty to ensure that payment amounts it orders be just and reasonable to both the utility and consumers."[355] The OEB need not approve every submitted cost nor are investors guaranteed a return on their investment; however, in order for the current utility structure to function, the utility must be able to recover its costs over the long run.

The legislation does not establish a presumption of prudence, but instead, places the burden on the utility to prove its costs are just and reasonable. The Supreme Court of Canada indicated that the distinction between "forecast" and "committed" may be helpful to a court reviewing the reasonableness of a regulator with such discretion. Applying a no-hindsight prudence review to forecast costs (that is, costs that the utility has the discretion to avoid) would be illogical.[356]

Here, the Court characterized labour costs as partly committed costs and partly subject to management discretion as there was flexibility in staffing levels within the negotiated collective agreement. Despite finding partially committed costs, the Supreme Court held that based on the regulatory scheme, it was not unreasonable for the OEB to make its determination without using a no-hindsight prudence review. Disallowing OPG's claim for operating costs would not discourage future investment, as labour costs are a necessity, versus capital costs, which are necessary to ensure viability and future growth. It was reasonable for the OEB to exercise its discretion to reject the costs "to send a clear signal that OPG must take responsibility for improving its performance."[357]

2. ATCO GAS V. ALBERTA (UTILITIES COMMISSION)

a. Background and Issues

Like the *OPG Decision*, *ATCO* involves an attempt to recover costs through inclusion in rates approved by the AUC. The ATCO applicants (ATCO Utilities) were both natural gas and electric utilities, governed by the *Gas Utilities Act*[358] and the *EUA*.[359] ATCO sought AUC

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355 *Ibid* at para 7.
356 *Ibid* at paras 82–83.
357 *Ibid* at para 120, citing *Re Ontario Power Generation Inc*, 3011 LNONOEB 57 (QL) at para 350.
358 RSA 2000, c G-5 [*GUA*].
359 *Supra* note 137.

approval of costs stemming from providing increased payments under pension plans to match increased cost of living figures in the consumer price index. In reaching its decision, the AUC reviewed benchmark evidence of comparative entities, which showed that increasing benefits to match 100 percent of the consumer price index annually was not standard practice. The AUC disallowed the ATCO Utilities' application for 100 percent recovery, determining that 50 percent of the consumer price index increase (up to a maximum of 3 percent) was reasonable. The Court of Appeal dismissed the ATCO Utilities' appeal and the Supreme Court of Canada granted leave.

Set in the context of a different regulatory framework, the central issue was the same at in the *OPG Decision*: "when — if ever — a regulator is required to apply a particular regulatory tool known as the 'prudent investment test' in assessing a utility's costs."[360] The ATCO Utilities argued that the AUC was obligated — but failed to — undertake a prudence analysis and include all prudently incurred costs in the revenue requirement. Further, the utilities asserted that the prudence analysis cannot be based on hindsight. Like OPG, the ATCO Utilities argued that where the AUC does not explicitly find the costs are not prudent, there is a presumption of prudence.

b. Decision

The standard of review for cases involving ratemaking is reasonableness, as it is central to the regulator's expertise. The Supreme Court of Canada applied the principles from the *OPG Decision* and held that the AUC's decision was reasonable, dismissing the appeal. Both the *EUA* and the *GUA* incorporated the key regulatory principle that utilities have the opportunity to recover prudent costs and expenses through approved rates. As in the *OPG Decision*, neither of the Alberta statutes requires analysis to be conducted under a "prudence methodology." The *EUA* requires the AUC to consider recovery of various "prudent" or "prudently incurred" expenses. The *GUA* entitles gas utilities to recover costs where the AUC determines them to be prudent.

The Supreme Court of Canada engaged in statutory interpretation and concluded that in the utility regulation context, "prudent costs" are synonymous with reasonable costs. Without a specific reference or any implied time period in the *EUA*, the AUC was not required to interpret the use of "prudent costs" to import a no-hindsight rule. Neither the *GUA* nor the *EUA* create a presumption of prudence; instead, both place the burden of establishing just and reasonable tariffs on the applicant utility. The AUC can employ whatever considerations or analytical tools it deems necessary, in its expertise, to determine whether the costs and expenses are prudent (or reasonable). The AUC's ultimate obligation is to ensure that the rates incorporating a utility's costs are just and reasonable.

The ATCO Utilities argued that the AUC was overly focused on reducing consumer rates. The Supreme Court of Canada stated that concern with the effect on consumers cannot ground a decision to refuse cost recovery. The AUC must still consider consumer interests, but this consideration is built-in to the requirement that a utility can only recover its reasonable expenses. Impacts on consumers due to increased rates will always be a

[360] *ATCO*, *supra* note 348 at para 2.

consideration. This is appropriate so long as it is not the sole reason for disallowing utility recovery. In reaching its decision, the AUC grounded its reasoning in prudence and not in rate increases for consumers.

C. SIGNIFICANT DECISIONS PERTAINING TO ALBERTA'S ELECTRICITY MARKET

1. *MARKET SURVEILLANCE ADMINISTRATOR ALLEGATIONS AGAINST TRANSALTA CORPORATION ET AL., MR. NATHAN KAISER AND MR. SCOTT CONNELLY, ALBERTA UTILITIES COMMISSION, DECISION 3110-D01-2015*[361]

On 27 July 2015 the AUC rendered a landmark decision finding that TransAlta Corporation, TransAlta Energy Marketing Corporation and TransAlta Generation Partnership (collectively TransAlta) had engaged in conduct that breached the *Fair, Efficient and Open Competition Regulation* (*FEOC*) and the *EUA*.[362] As a result, TransAlta will have to pay a \$56 million dollar fine, which represents \$26,920,814.31 in damages for disgorgement of profits and \$25 million dollars as a monetary penalty.

a. Legislative Background

To provide context to this decision, it is important to understand how the Alberta energy market is regulated. In 1996 the government took steps to restructure and deregulate the energy market, allowing the price of energy to be determined by market competition. As part of this deregulation the legislation introduced the use of PPAs.

In addition to the introduction of the PPAs, the government also enacted the *EUA* and the *FEOC*. The *EUA* "sets out the regulatory framework for the operation of Alberta's wholesale electricity market."[363] In particular, section 6 of the *EUA* states "[m]arket participants are to conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market."[364] This statement is further supported by *FEOC* which specifically sets out what types of conduct do not support the fair, efficient, and openly competitive operation of the market. In this case, the focus of the Market Surveillance Administrator (MSA) and AUC was on sections 2(h) and 2(j) of *FEOC*, which discuss restricting or preventing competition, a competitive response or market entry, and manipulating market prices.[365] Ultimately, both of these Acts are intended to ensure that the market operates in a way that allows competition to be fair and open. The MSA then, as the watchdog of the Alberta electricity market, supervises the market to ensure the regulations are being followed by Buyers and Producers.

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361 *Market Surveillance Administrator Allegations Against TransAlta Corporation et al, Mr. Nathan Kaiser and Mr. Scott Connelly* (27 July 2015), 3110-D01-2015, online: AUC <www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2015/3110-D01-2015.pdf> [*Market Surveillance*].

362 *EUA*, *supra* note 137; *Fair, Efficient and Open Competition Regulation*, Alta Reg 159/2009 [*Competition Regulation*].

363 *Market Surveillance*, *supra* note 361 at para 46.

364 *EUA*, *supra* note 137, s 6.

365 *Competition Regulation*, *supra* note 362.

b. Brief Facts

The MSA began investigating TransAlta after receiving a complaint that TransAlta was using its discretion to time the outages at its coal-fired generating units in a way that allowed TransAlta to maximize prices. Four outages in particular were at issue:

- 19 November 2010 at Sundance 5;
- 23 November 2010 at Sundance 2;
- 13-16 December 2010 at Sundance 1, Keephills 1, and Sundance 6; and
- 16 February 2011 at Keephills 2.

The MSA submitted to the AUC that TransAlta misused its discretionary authority by choosing to take outages at times of high demand and low supply, and that this was a breach of section 6 of the *EUA* and sections 2(h) and (j) of *FEOC*. The MSA's investigation revealed that TransAlta had developed an internal "Portfolio Bidding Strategy" and at the AUC hearing the MSA submitted that under this strategy TransAlta used economic withholding and discretionary outages to intentionally increase market prices.

c. Decision

In its decision, the AUC found that TransAlta's Portfolio Bidding Strategy was in violation of section 6 of the *EUA* and sections 2(h) and (j) of *FEOC*. The four outages listed above had been timed on the basis of market conditions, not as TransAlta contended, because they were necessary to protect life, property, or the environment. The AUC held that TransAlta could have taken the outages at off-peak hours and that choosing not to do so was a decision driven entirely by the Portfolio Bidding Strategy. The AUC also found that TransAlta had allowed one of the two named employees to trade while in possession of non-public outage records. However, the AUC held that the individual took all reasonable steps to avoid a breach of the *FEOC*, and therefore, the AUC could not find the individual in breach of the *EUA*. Accordingly, all allegations against individuals were dismissed.

On 30 September 2015, TransAlta reached a settlement with the MSA and consented to a $56 million dollar payment.[366]

2. *INDEPENDENT POWER PRODUCERS' SOCIETY OF ALBERTA v. INDEPENDENT SYSTEM OPERATOR (ALBERTA ELECTRIC SYSTEM OPERATOR)*[367]

On 7 March 2016, the Alberta Court of Queen's Bench dismissed an application brought by the Independent Power Producers' Society of Alberta (IPPSA) asking the Court to review the Independent System Operator's (ISO) decision regarding the timing of publication and information to be included in the Historic Trading Reports (HTR). The MSA was an intervenor in this action.

366 TransAlta, News Release, "TransAlta Reaches Agreement with Market Surveillance Administrator" (30 September 2015), online: <www.transalta.com/newsroom/news-releases/2015-09-30/transalta-reaches-agreement-market-surveillance-administrator>.

367 2016 ABQB 133, 2016 ABQB 133 (CanLII) [*IPPSA*].

a. Background and Issues

Under the *EUA*, the ISO is responsible for planning the electric transmission system in Alberta, promoting a fair, efficient, and openly competitive market in electricity in Alberta, and for directing the safe, reliable, and economic operation of that system.[368] This includes publishing HTR reports on the offers made by generators to the Alberta power pool to dispatch power at specific quantities and prices.[369] Previously, the ISO released this information approximately 5 to 10 minutes after the end of each hour.

This dispute arose because of concerns the MSA had regarding HTR reports. In particular, the MSA was concerned the HTR reports were contributing "to [the] precipitous increases in the pool price for electricity and undermines the fair, efficient and openly competitive operation of the market by relieving competitive restraints on the exercise of market power";[370] and took the position that the ISO could have met its obligations under section 6 of *FEOC* by simply providing Merit Order Snapshot Reports.[371] In response to these concerns, the ISO agreed to make changes to the HTR. On 8 January 2015, the ISO issued a notice to all market participants stating that the HTR would be published 12 hours after the hour in which offers are made.[372]

These changes to the HTR concerned IPPSA, and on 19 March 2015, IPPSA filed an application for judicial review of the ISO's decision, seeking to set aside the changes to the HTR. On 30 September 2015, this application was adjourned *sine die* with the consent of the ISO and IPPSA. After this adjournment, on 2 December 2015, the MSA referred the matter to the AUC, pursuant to section 51(2) of the *Alberta Utilities Commission Act*.[373]

The MSA's application to the AUC triggered IPPSA to re-schedule its previously adjourned application for judicial review, with IPPSA submitting that if it was successful "in the judicial review proceeding regarding the format and publication timing of the HTR, there would be no basis for the Commission proceeding."[374]

b. Decision

Given that the MSA asked the AUC to conduct a hearing to determine whether the current publication of the HTR is inconsistent with *FEOC*,[375] the Court of Queen's Bench concluded that it should defer any judicial review of this question until after the AUC hearing takes place. The Court's rationale was that the AUC is specifically empowered to hear questions of this nature, and more importantly, the AUC is a body specialized in the regulation of utilities. As such, the Court of Queen's Bench held that it should defer any decision on this matter until after the AUC hearing.[376] This decision confirms the Courts' recognition of the

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368 *Ibid* at para 5, citing *EUA*, *supra* note 137, s 17.
369 *IPPSA*, *ibid* at para 8.
370 *Ibid* at para 9, citing *IPPSA*, *supra* note 367 (Affidavit of Dr. Ayres, Chief Executive Officer of the MSA).
371 *IPPSA*, *ibid*.
372 *Ibid* at para 10.
373 SA 2007, c A-37.2, s 51.
374 *IPPSA*, *supra* note 367 at para 17.
375 *Ibid* at para 16.
376 *Ibid* at paras 35–37.

AUC's expertise in respect of electricity matters; and that certain complex decisions relating to the regulation of electricity are appropriately left to the AUC to determine at first instance.[377]

An oral hearing before the AUC on the publication of historical trading issue was scheduled to take place on 20 June 2016.

377 Nigel Bankes, "Court Confirms that the AUC Can Take the Lead in Examining the Scope of the ISO's Reporting Obligations" (11 March 2016), *ABlawg* (blog), online: <www.ablawg.ca/wp-content/uploads/2016/03/Blog_NB_AUC_March2016.pdf>.