RECENT LEGISLATIVE AND REGULATORY DEVELOPMENTS OF INTEREST TO ENERGY LAWYERS

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This article provides an overview of recent regulatory and legislative developments of interest to Canadian energy lawyers from April 2021 to March 2022. It includes discussions of recent regulatory decisions and related judicial decisions, as well as changes to regulatory and legislative regimes impacting energy law. This article also discusses and comments on a number of ongoing regulatory and legislative developments to watch in the coming year. Topics discussed include the opportunities and challenges posed by decarbonization efforts, Aboriginal law, standard of review, and other natural resource and power developments.

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I. INTRODUCTION

The Canadian energy landscape is changing. In past years, oil booms and busts have dominated the energy news. However, despite oil reaching $100 in February 2022, the decarbonization efforts, and not the economic wins from increased oil prices, are still driving policy and industry announcements over the last year. Governments are looking to spur innovation in areas like carbon capture, utilization and storage, clean electricity, and alternative fuel sources, like hydrogen. Governments are also looking for ways to increase participation with Indigenous groups in these areas.

These are trends that are likely to continue in coming years as governments across Canada set more stringent goals for reducing and eliminating emissions and continue to make commitments regarding reconciliation.

II. STANDARD OF REVIEW

In 2019, the Supreme Court of Canada reconsidered the approach to the standard of review for administrative decisions in *Canada (Minister of Citizenship and Immigration) v. Vavilov*.[1] One significant change was the application of the appellate standard of review for the statutory appeal of administrative decisions. Under the appellate standard, the correctness standard applies to questions of law and the palpable and overriding error standard applies to questions of fact or mixed law and fact from which a question of law is not extricable.[2]

1 2019 SCC 65 [*Vavilov*].
2 *Housen v Nikolaisen*, 2002 SCC 33.

After several years of applying *Vavilov*, the intention to simplify the issue of standard of review has only been partly successful.

In many cases, statutory appeals of administrative decision-makers are limited to questions of law or jurisdiction,[3] in which case *Vavilov* suggests the standard of review will be correctness. In Alberta, at least, that has not always been the case, as discussed below.

Despite the apparent clarity provided by the Supreme Court on the standard of review to apply to statutory appeals, the application of *Vavilov* has not been straightforward at the Alberta Court of Appeal. Some Justices have grappled with applying a correctness standard for questions of law when it has traditionally deferred to the expertise of the administrative tribunal. A good example is the concurring judgment of Justice O'Ferrall in *Dorin v. EPCOR Distribution and Transmission Inc*.[4]

Another example within the timeline of this article is the Alberta Court of Appeal's decision in *TransAlta Corporation v. Alberta (Utilities Commission)*,[5] where the majority started by stating, in *obiter*, that *Vavilov* has left open whether the existence of a statutory appeal mechanism should always mean the application of the appellate standard of review, leaving the door open to the possibility that the enabling legislation, in this case the *AUCA*,[6] may not have to be read to require the court to apply correctness for all questions of law.[7] This reasoning is difficult to reconcile with the clear direction of the Supreme Court of Canada in *Vavilov*.

Application of *Vavilov* also has the potential to cause the relitigation of questions of law that were previously decided on a reasonableness standard. This was the case in *ATCO Electric Ltd v. Alberta (Utilities Commission)*.[8] ATCO Electric Ltd. (ATCO Electric) sought permission to appeal an Alberta Utilities Commission (AUC) decision that determined that the destruction of ATCO Electric's utility assets by the fires in Fort McMurray was an "extraordinary retirement" and that the stranded costs of these assets must be borne by ATCO Electric shareholders,[9] a result consistent with an earlier Alberta Court of Appeal decision.[10] Permission to appeal this AUC decision was granted on the basis, in part, that the Alberta Court of Appeal's review in *Fortis* that considered the regulatory rate treatment of stranded or destroyed utility assets, had been reviewed on a reasonableness standard.[11] The result of this appeal, in particular the relitigation of the issues around stranded assets, will be of specific interest to electric utilities in Alberta.

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3 See e.g. *Alberta Utilities Commission Act*, SA 2007, c A-37.2, s 29 [*AUCA*].

4 2020 ABCA 391 at para 24.

5 2022 ABCA 37 [*TransAlta*].

6 *Supra* note 3.

7 *TransAlta*, *supra* note 5 at paras 25–26.

8 2022 ABCA 73 [*ATCO Electric*].

9 *ATCO Electric Ltd, Z Factor Adjustment for the 2016 Regional Municipality of Wood Buffalo Wildfire* (2 October 2019), 21609-D01-2019, online: AUC <www2.auc.ab.ca/Proceeding21609/ProceedingDocuments/21609_X[]_21609-D01-2019ATCOElectricZFactorAdjustm_0080.pdf>.

10 *FortisAlberta Inc v Alberta (Utilities Commission)*, 2015 ABCA 295 [*Fortis*]. *Fortis* was an appeal of the AUC's Utility Asset Disposition decision: *Utility Asset Disposition* (26 November 2013), 2013-417, online: AUC <www2.auc.ab.ca/h006/Proceeding20/ProceedingDocuments/2013-417%20u_0364.pdf>. For more background on utility asset disposition in Alberta: see Lou Cusano et al, "Prudence, Stranded Assets, and the Regulation of Utilities: A Review of Alberta Utility Regulatory Principles in a Post-*Stores Block* Era" (2018) 56:2 Alta L Rev 403.

11 *ATCO Electric*, *supra* note 8 at paras 32–33.

Two other standard of review decisions worth mentioning are *O.K. Industries Ltd. v. District of Highlands*[12] and *Rio Tinto Alcan inc. c. Régie de l'énergie*.[13] Both cases considered whether the presumption of reasonableness could be rebutted in a judicial review application.

In *OK Industries*, the British Columbia Court of Appeal considered whether municipal bylaws applied to a quarry that had received a mining permit under provincial legislation. In its standard of review analysis, the British Columbia Court of Appeal recognized a new exception to the presumption of reasonableness after finding that the question in the case did not fit comfortably into the categories of correctness described in *Vavilov*. The British Columbia Court of Appeal held that the answer to whether the bylaw applied to the quarry required consistency, a final and determinate answer, and had "significant legal consequences to the institutions of the provincial and municipal governments that purport to regulate mining resources in British Columbia."[14] One scholar suggests that a new exception may not have been required in this case given the question at issue was not one assigned to an administrative decision-maker — or in other words, there was no specific decision being reviewed by the municipality or the mines inspector who was delegated authority to grant the mining permit — and therefore, the question was within the inherent jurisdiction of the court.[15]

In *Rio Tinto*, the Superior Court (Civil) of Quebec rejected Rio Tinto Alcan's argument that the Régie de l'énergie's decision in Decision D-2017-110 to adopt reliability standards should be reviewed for correctness. Rio Tino Alcan argued that the adoption of the reliability standards may result in the application of the *Business Concerns Records Act*,[16] to certain documents that the reliability standard may require it to provide, and accordingly, it was a matter of general law of paramount importance to the legal system as a whole. The Court relied on a presumption of reasonableness in *Vavilov* and rejected the notion that the Régie de l'énergie's decision was of paramount importance to the legal system as a whole but important to a limited class (namely, only those who are obliged to comply with the standard). The Court also noted that the application of the *Business Concerns Records Act* was not a question that required a definitive answer, but rather depended on a question of mixed law and fact and the application of said *Act* was manifestly hypothetical and should not change the standard of review.[17]

The apparently straightforward direction of the Supreme Court in *Vavilov* that appeals of questions of law under a statutory right of appeal from administrative and regulatory decisions are to be assessed using a correctness standard is proving to be not so straightforward. Nevertheless, one of the practical consequences of *Vavilov* is that lawyers should not assume that pre-*Vavilov* appeals decided on a reasonableness standard are the final word on an issue.

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12 2022 BCCA 12 [*OK Industries*].
13 2021 QCCS 993 [*Rio Tinto*].
14 *OK Industries*, *supra* note 12 at para 53.
15 Paul Daly, "Exceptional Circumstances? O.K. Industries Ltd. v. District of Highlands, 2022 BCCA 12" (14 January 2022), online (blog): *Administrative Law Matters* <www.administrativelawmatters.com/blog/2022/01/14/exceptional-circumstances-o-k-industries-ltd-v-district-of-highlands-2022-bcca-12/>.
16 CQLR c D-12.
17 *Rio Tinto*, *supra* note 13 at paras 51–55.

III. ABORIGINAL

The Truth and Reconciliation Commission of Canada issued its Calls to Action in 2015.[18] 2021 saw significant steps towards reconciliation and implementing these Calls to Action, including: the first National Day for Truth and Reconciliation on 30 September 2021;[19] the passage of federal legislation on the *United Nations Declaration on the Rights of Indigenous Peoples*;[20] significant settlements resolving Indigenous child welfare class actions[21] and compensation for past prolonged drinking water advisories;[22] heartbreaking revelations of unmarked graves as more residential school sites were searched, starting with the Kamloops Indian Residential School in May 2021;[23] and an eventual apology from Pope Francis for the Catholic Church's role in abuses at residential schools.[24]

Indigenous peoples have also achieved significant wins before the courts, with the British Columbia Supreme Court finding a breach of treaty rights based on the cumulative impacts of decades worth of industrial development for the first time, prompting significant regulatory process changes, and advancements in the jurisprudence on the honour of the Crown and fiduciary duties owed to Indigenous peoples. However, the case law also demonstrates how much more work needs to be done, with governments arguing that *UNDRIP* legislation does not have any immediate impacts,[25] and the Divisional Court of the Ontario Superior Court of Justice finding that the Government of Ontario engaged in consultation that was "corrosive" to reconciliation.[26]

A. CUMULATIVE IMPACTS

On 29 June 2021, the British Columbia Supreme Court issued the first decision in which a Canadian court has found an infringement of Indigenous treaty rights as the result of the cumulative effects of various government policies and permitted projects over decades, rather than as a result of a specific action or project.[27]

The claimants, Blueberry River First Nations (Blueberry River), are based in northeast British Columbia and adhere to Treaty 8. Treaty 8 lands have been subject to significant industrial development, including in the agriculture, forestry, mining, hydroelectric, and oil

18 *Truth and Reconciliation Commission of Canada: Calls to Action* (Winnipeg: Truth and Reconciliation Commission of Canada, 2015), online: *First Nations Child & Family Caring Society* <fncaringsociety.com/sites/default/files/truth_and_reconciliation_commission_of_canada_calls_to_action.pdf>.

19 Government of Canada, "National Day for Truth and Reconciliation," online: <www.canada.ca/en/canadian-heritage/campaigns/national-day-truth-reconciliation.html>.

20 *United Nations Declaration on the Rights of Indigenous Peoples Act*, SC 2021, c 14 [Canada *UNDRIP Act*].

21 Brett Forester & Fraser Needham, "Canada, First Nations Reveal Details of $40B Draft Deals to Settle Child Welfare Claims," *APTN National News* (4 January 2022), online: <www.aptnnews.ca/national-news/canada-first-nations-reveal-details-of-40b-draft-deals-to-settle-child-welfare-claims/>.

22 *Tataskweyak Cree Nation v Canada (AG); Curve Lake First Nation v Canada (AG)*, 2021 MBQB 275.

23 Courtney Dickson & Bridgette Watson, "Remains of 215 Children Found Buried at Former B.C. Residential School, First Nation Says," *CBC News* (29 May 2021), online: <www.cbc.ca/news/canada/british-columbia/tk-eml%C3%BAps-te-secw%C3%A9pemc-215-children-former-kamloops-indian-residential-school-1.6043778>.

24 Olivia Stefanovich, "Pope Francis Apologizes to Indigenous Delegates for 'Deplorable' Abuses at Residential Schools," *CBC News* (1 April 2022), online: <www.cbc.ca/news/politics/pope-francis-responds-indigenous-delegations-final-meeting-1.6404344>.

25 See e.g. *Thomas and Saik'uz First Nation v Rio Tinto Alcan Inc*, 2022 BCSC 15 [*Saik'uz First Nation*].

26 *Attawapiskat First Nation v Ontario*, 2022 ONSC 1196 at para 135.

27 *Yahey v British Columbia*, 2021 BCSC 1287 [*Yahey*].

and gas sectors. Blueberry River alleged that the cumulative effects of the industrial development had a significant and adverse impact on their ability to exercise their treaty rights, resulting in a breach of Treaty 8 and an infringement of Blueberry River's rights.

The British Columbia Supreme Court found that the impacts of this industrial development meaningfully diminished Blueberry River's rights to hunt, fish, and trap,[28] and that the province's processes did not adequately consider treaty rights or cumulative impacts, contributing to the diminishment.[29] The Court found that the province had been aware of the cumulative impacts of development for two decades, but failed to respond in a manner that implemented treaty promises or upheld the honour of the Crown.[30]

The British Columbia Supreme Court issued two declarations in relation to the impacts on Blueberry River's treaty rights:

- The province breached its Treaty 8 obligations, including the honour of the Crown and its fiduciary duties, by permitting the cumulative impacts of industrial development on Blueberry River's treaty rights.

- The province has infringed Blueberry River's Treaty 8 rights by taking up lands to such an extent that there are not sufficient and appropriate lands for Blueberry River members to meaningfully exercise their treaty rights.[31]

The British Columbia Supreme Court also issued two forward-looking declarations as a remedy:

- The province is prohibited from continuing to authorize activities that breach Treaty 8 or that unjustifiably infringe on Blueberry River's treaty rights.

- The province and Blueberry River are required to consult and negotiate enforceable mechanisms to assess and manage the cumulative impacts of industrial developments on Blueberry River's treaty rights and ensure that those rights are respected.[32]

The British Columbia Supreme Court suspended the prohibition against authorizing activities for six months to allow the parties to negotiate changes to the regulatory regime that recognize and respect treaty rights.[33] While this suspension may have provided some limited amount of comfort for industry, the negotiations mandated by the British Columbia Supreme Court represent a significant undertaking, and the Government of British Columbia and Blueberry River are still in negotiations well past the six-month suspension. The British Columbia Supreme Court's decision will continue to create significant uncertainty for new projects being considered or projects with proposed expansions in the Treaty 8 region of British Columbia until a long-term solution is implemented.

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28 *Ibid* at para 1129.
29 *Ibid* at para 1751.
30 *Ibid* at para 1750.
31 *Ibid* at para 1884.
32 *Ibid* at para 1888.
33 *Ibid* at para 1891.

On 28 July 2021, the British Columbia Attorney General and Minister Responsible for Housing, David Eby, announced that the province would not appeal the decision.[34] Then, on 7 October 2021, the province announced that it had reached an initial agreement with Blueberry River to support healing the land and provide stability and certainty for the forestry and oil and gas permit holders in Blueberry River's traditional territory.[35]

Under the agreement, the province will establish a $35 million fund for Blueberry River to undertake activities to heal the land, including: land, road, and seismic restorations; river, stream and wetland restoration; habitat connectivity; native seed and nursery projects; and training for restoration activities. In addition, $30 million will be allocated to support the Blueberry River in protecting their Indigenous way of life, including: work on cultural areas; traplines; cabins and trains; educational activities and materials; expanding Blueberry River's resources and capacity for land management; and wildlife management, habitat enhancements, and research. As part of the agreement, 195 forestry and oil and gas projects that were permitted or authorized prior to the British Columbia Supreme Court's decision, but not yet started, will proceed. However, 20 authorizations relating to development in areas of high cultural importance will not proceed without further negotiation and agreement from Blueberry River.[36]

The Government of British Columbia and Blueberry River are continuing to work on developing an interim approach for reviewing new natural resource activities that balance treaty rights, the economy, and the environment. Once an interim agreement is in place, the province and Blueberry River will work on long-term solutions that protect treaty rights and the Indigenous way of life. The province is also starting similar discussions with other Treaty 8 Nations.

In developing the long-term strategy, British Columbia and Blueberry River may look to the Northwest Territories for inspiration. The Northwest Territories Cumulative Impact Monitoring Program (NWT CIMP), in place since 1999, requires that environmental information is collected and available to support resource management decision-making.[37] The NWT CIMP issued its five-year action plan for 2021–2025 in December 2021. The action plan builds on successes from previous years, and continues to advance the better understanding of cumulative impacts, with a greater emphasis on long-term and regional monitoring and analysis.[38]

It remains to be seen whether the British Columbia Supreme Court's reasoning in *Yahey* will be adopted by courts outside of British Columbia as similar claims make their way through the courts in other jurisdictions.

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34 Government of British Columbia, Attorney General, Statement, "Attorney General's Statement on Yahey v. British Columbia" (28 July 2021), online: <news.gov.bc.ca/releases/2021AG0117-001488>.

35 Government of British Columbia, Indigenous Relations and Reconciliation, News Release, "B.C., Blueberry River First Nations Reach Agreement on Existing Permits, Restoration Funding" (7 October 2021), online: <news.gov.bc.ca/releases/2021IRR0063-001940>.

36 *Ibid*.

37 Northwest Territories, Environment and Natural Resources, *NWT Cumulative Impact Monitoring Program (NWT CIMP): Action Plan 2021-2025* (Northwest Territories: Environment and Natural Resources, December 2021) at 2, online: <www.enr.gov.nt.ca/sites/enr/files/resources/2021-25_nwt_cimp_action_plan_final_dec2021.pdf>.

38 *Ibid* at 3.

The Beaver Lake Cree Nation has advanced a similar cumulative impacts claim in Alberta. The claim was started in 2008,[39] and is scheduled for a 120-day trial to begin in 2024.[40] The case has already been to the Supreme Court of Canada on the issue of advanced costs.[41]

Saskatchewan is also facing a cumulative impacts claim being advanced by Carry the Kettle First Nation, started in late 2017.[42]

It also remains to be seen whether other Canadian jurisdictions will change their approaches to considering cumulative impacts in response to this decision.

B. STATUS OF *UNDRIP* IN CANADA

British Columbia and the federal government have now enacted legislation on the *UNDRIP*.[43] The British Columbia legislation was passed in 2019,[44] and the federal legislation was passed in 2021.[45] Both require the government to prepare and implement an action plan, with consultation and co-operation with Indigenous peoples, to achieve the objectives of *UNDRIP*.[46] They must also prepare a report on the measures taken and the implementation on the action plan.[47] The primary difference between the two *Acts* is that the Canada *UNDRIP Act* includes a number of preamble statements that are not in the BC *UNDRIP Act*. British Columbia has gone a step further and has also enacted amendments to its *Interpretation Act* on 25 November 2021 requiring that every *Act* and Regulation in British Columbia be construed as upholding constitutionally protected Aboriginal and treaty rights, and in a manner consistent with *UNDRIP*.[48]

However, it is still early days since these *Acts* have been passed, and it remains to be seen how, or if, it will change the interpretation of, or drive amendments to, existing legislation. In *Saik'uz First Nation*, the plaintiffs argued that the BC *UNDRIP Act* is "an interpretive tool in support of robust recognition and accommodation of Aboriginal rights."[49] Meanwhile, the defendants, which include both the Government of British Columbia and the Government of Canada, argued that *UNDRIP* has never been implemented as law in Canada, and that the recent *UNDRIP* legislation has "no immediate impact on existing law and is simply 'a forward-looking' statement of intent that contemplates an 'action plan' yet to be prepared and implemented by either level of government."[50]

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39 *Anderson v Alberta*, 2022 SCC 6 at para 2.
40 *Ibid* at para 10.
41 *Ibid* at para 72.
42 Larissa Burnouf, "Ottawa, Saskatchewan Government Sued over Treaty Rights," *APTN National News* (17 January 2018), online: <www.aptnnews.ca/national-news/ottawa-saskatchewan-government-sued-treaty-rights/>.
43 *United Nations Declaration on the Rights of Indigenous Peoples*, GA Res 61/295, UNGAOR, 61st Sess, UN Doc A/RES/61/295 (2007), online: <www.un.org/development/desa/indigenouspeoples/wp-content/uploads/sites/19/2018/11/UNDRIP_E_web.pdf> [*UNDRIP*].
44 *Declaration on the Rights of Indigenous Peoples Act*, SBC 2019, c 44 [BC *UNDRIP Act*].
45 Canada *UNDRIP Act*, *supra* note 20.
46 *Ibid*, s 6; BC *UNDRIP Act*, *supra* note 44, s 4.
47 Canada *UNDRIP Act*, *ibid*, s 7; BC *UNDRIP Act*, *ibid*, s 5.
48 *Interpretation Act*, RSBC 1996, c 238, s 8.1.
49 *Saik'uz First Nation*, *supra* note 25 at para 210.
50 *Ibid* at para 211.

These arguments suggest that the passage of the *Acts* was more virtue signaling than a concrete commitment to real and meaningful change.

C. DEVELOPMENTS IN THE DUTY TO CONSULT

1. BENGA MINING: APPEAL BY TWO FIRST NATIONS OF THE REJECTION OF A COAL MINING PROJECT APPLICATION

Benga Mining Limited applied to the Alberta Energy Regulator (AER) for approval for a new open-pit metallurgical coal mine in the Crowsnest Pass area of Alberta.[51] Known as the Grassy Mountain Coal Project, it included surface mine pits and waste rock disposal areas, a coal-handling and processing plant, water management facilities, an overland conveyor system, and a rail loading facility. The project footprint was 1521 hectares, and it was forecast to employ about 400 workers and generate approximately $1.7 billion in royalties and taxes over its 23-year life.[52]

Benga entered into benefits agreements with both the Piikani Nation and the Stoney Nakoda Nation. The Piikani Nation supported the project and the Stoney Nakoda Nation did not object to it. The municipal district opposed the project.

The AER and the Canadian Environmental Assessment Agency carried out a joint review and after holding a hearing, the joint review panel (JRP) determined that the project was not in the public interest and that the adverse environmental effects outweighed the positive economic impacts.[53] Among other things, the JRP concluded that the project would cause loss of lands used for traditional activities and that this would adversely affect Indigenous groups who use the area, even though the affected First Nations all stated they did not object to the project.[54]

Benga, the Piikani Nation, and Stoney Nakoda Nation applied for permission to appeal, but on 28 January 2022 the Alberta Court of Appeal denied the application.[55] The Stoney Nakoda and Piikani Nations sought permission to appeal the *JRP Report* on a number of grounds from which three themes emerge:

- the JRP failed to adequately consider the positive benefits that would have accrued to the Nations in the context of the public interest test and in the context of the honour of the Crown and reconciliation;

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51 The project was located in the Municipal District of Ranchland No 66.

52 Canada, Joint Review Panel Established by the Federal Minister of Environment and Climate Change and the Alberta Energy Regulator, *Report of the Joint Review Panel: Benga Mining Limited Grassy Mountain Coal Projec*t, Decision 2021 ABAER 010, Catalogue No En106-239/2021E-PDF (Calgary: Alberta Energy Regulator, 17 June 2021) at paras 2, 2795, online: <static.aer.ca/prd/documents/decisions/2021/2021ABAER010.pdf> [*JRP Report*].

53 *Ibid* at para 3048.

54 *Ibid* at ix.

55 *Benga Mining Limited v Alberta Energy Regulator*, 2022 ABCA 30 [*Benga Mining*].

- once it considered not approving the project, the JRP ought to have asked the Nations for further information or should have requested that the Crown engage further with the Nations regarding implications of not approving the project; and

- the JRP made determinations regarding the validity of the Nations' rights and interests when it was not permitted to do so under the JRP's terms of reference.[56]

The Court rejected the Nations' public interest and honour of the Crown arguments, noting that neither Nation had filed their benefit agreements on the JRP proceeding record, which prevented the JRP from undertaking a detailed assessment of the project on the socioeconomic conditions of the Nations. However, the Court concluded that this did not prevent the JRP from considering whether the project was in the public interest, in a manner consistent with the honour of the Crown.[57]

The Court also rejected the Nations' argument that the JRP had an obligation to seek information from them about how a rejection of the project would affect them, principally because both Nations had full participation rights in the hearing and they were aware that the JRP process could lead to several outcomes, including rejecting the project or approving it with conditions.[58]

This is an interesting case because it reverses the dynamic that is often seen in large energy projects where the municipal district supports the application because of the socioeconomic benefits, and First Nations do not support the project because of the impacts that the project may have on traditional land uses. It also illustrates the point that a regulator is not bound to accept the support of affected First Nations as conclusive evidence that a project will not have an adverse effect on Indigenous groups who use the land.

Benefit agreements between project proponents and First Nations are often not filed in regulatory proceedings, but are instead described in general terms. However, *Benga Mining* reinforces the point that parties ultimately bear the consequences of their decisions regarding what evidence they choose to put (or not put) on the record.

2. *ATTAWAPISKAT FIRST NATION V. ONTARIO*

This case deals with Ontario's duty to consult and accommodate the Attawapiskat First Nation (Attawapiskat) when issuing mineral exploration permits.[59] The permits were for exploration rather than development.[60] Attawapiskat brought an application for judicial review of the decision to issue the permits on the basis that the Government of Ontario had not adequately assessed or fulfilled the duty to consult and accommodate, and sought to have the permits quashed.[61]

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56 *Ibid* at paras 79–83.
57 *Ibid* at para 109.
58 *Ibid* at para 125.
59 *Attawapiskat First Nation v Ontario*, 2022 ONSC 1196 at paras 1–2 [*Attawapiskat*].
60 *Ibid* at para 85.
61 *Ibid* at para 2.

The Ontario Superior Court of Justice agreed with the Government of Ontario that the scope of the duty to consult was at the low-end of the spectrum given the limited nature, geographic scope, and duration of the projects.[62] This was despite Attawapiskat's "high level" expert evidence about cumulative effects and potential impacts on caribou.[63]

However, the province failed to foster meaningful consultation. Attawapiskat received pro forma letters initially, and no other communication took place for several months, at which point the province imposed tight time constraints. The Court found that the process was corrosive to reconciliation.[64] The province mistakenly referred Attawapiskat to a link where proponents were expected to respond to questions or concerns.[65] Attawapiskat therefore wrote repeatedly to the project proponent, who did not respond. The Court called this failure to respond "an affront to reconciliation."[66]

The province did not know this was occurring, and when it eventually wrote to Attawapiskat again, the province said it intended to issue a decision within a month.[67] Attawapiskat provided general information, which it identified as high-level and preliminary.[68] The province requested further information on 3 September 2020, and then approved the projects on 8 September 2020. The Court found that it was unrealistic to expect Attawapiskat to provide additional information in such a short time period.[69] The Court found that the letters sent by the province did not reflect an intention of substantially addressing Attawapiskat's concerns, and did not adequately take into consideration the Indigenous cultural context, and were ultimately not sufficient to constitute meaningful consultation.[70]

The Court acknowledged that, for consultation to be meaningful, it must occur before the activity begins.[71] However, the Court declined to quash the permits in this case.[72] The Court noted that there had been time for the Attawapiskat to provide additional information, which it had not done.[73] The Court viewed this as a question about whether further conditions were required, not whether the permits should be issued. In this context, the Court determined that it would be unreasonable to quash the permits based on the record before it.[74]

3. *ERMINESKIN CREE NATION V. CANADA (ENVIRONMENT AND CLIMATE CHANGE)*

This case deals with the duty to consult in the context of a decision to designate a project under the *Impact Assessment Act*.[75] The federal Minister of Environment and Climate Change designated the Vista Coal Mine Phase II Expansion Project under the *IAA*, which triggers the

62 *Ibid* at para 86.
63 *Ibid* at para 87.
64 *Ibid* at para 110.
65 *Ibid* at paras 113–14.
66 *Ibid* at para 115.
67 *Ibid* at para 116.
68 *Ibid* at para 119.
69 *Ibid* at para 120.
70 *Ibid* at para 123.
71 *Ibid* at para 145.
72 *Ibid* at para 146.
73 *Ibid* at para 147.
74 *Ibid* at para 148.
75 SC 2019, c 28, s 1 [*IAA*].

need for a federal impact assessment.[76] The applicant, Ermineskin Cree Nation (Ermineskin) successfully applied for judicial review of that decision.

Ermineskin entered into an impact benefit agreement with the project proponent, Coalspur Mines (Operations) Ltd. (Coalspur). Ermineskin argued that the decision to designate the project adversely impacted its Aboriginal and treaty rights, including economic opportunities created by its relationship with Coalspur. [77] The federal government argued that losing the benefits of the impact benefit agreement was not an adverse impact on an Aboriginal or treaty right, and therefore did not trigger the duty to consult.[78]

The Federal Court disagreed. The Court held that the jurisprudence required a generous and purposive approach to the honour of the Crown and the duty to consult, and that the duty to consult extends to include economic benefits closely related to and derived from Aboriginal rights.[79] The Court also found that the decision to designate the project had delayed, and could further delay or end, the economic benefits to Ermineskin under its impact benefit agreement.[80]

In making his decision, the Minister only heard from Indigenous parties who were seeking to have the project designated under the *IAA*. Ermineskin was "frozen out" of the process.[81] As a result, the duty to consult was breached and judicial review was granted.[82]

Following the Federal Court's decision, the federal Minister of Environment and Climate Change reconsidered the project, and on 19 July 2021 again concluded that the project warranted designation.[83]

The decision has been appealed to the Federal Court of Appeal. On 22 February 2022, Coalspur filed a motion to have the appeal dismissed for mootness.[84]

4. AUC BUFFALO PLAINS WIND FARM INC.

In this decision, the AUC approved the 514.6 megawatt Buffalo Plains Wind Power Plant.[85] The project was located within the Blackfoot traditional territory, and was approximately 20 kilometers from *Iniskim Umaapi*, also known as the Majorville Cairne and Medicine Wheel. Blood Tribe/Kainai (Kainai) and Siksika Nation (Siksika) intervened in the application.[86]

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76 *Ermineskin Cree Nation v The Minister of Environment and Climate Change, The Attorney General of Canada and Coalspur Mines (Operations) Ltd*, 2021 FC 758 at para 1 [*Ermineskin*].
77 *Ibid* at para 5.
78 *Ibid* at para 6.
79 *Ibid* at paras 7–8, 105–107.
80 *Ibid* at paras 18, 117.
81 *Ibid* at paras 25–26, 129.
82 *Ibid* at para 132.
83 Impact Assessment Agency of Canada, "Minister's Response" (29 September 2021), online: *Government of Canada* <iaac-aeic.gc.ca/050/evaluations/document/141492>.
84 *Minister of Environment and Climate Change v Ermineskin Cree Nation* (22 February 2022), Calgary, AB FCA A-254-21 (motion to dismiss), online: <apps.fca-caf.gc.ca/pq/IndexingQueries/infp_RE_info_e.php?court_no=A-254-21&select_court=A>.
85 *Buffalo Plains Wind Farm Inc: Buffalo Plains Wind Farm* (10 February 2022), 26214-D01-2022, online: AUC <efiling-webapi.auc.ab.ca/Document/Get/712219#hq=26214-d01-2022 > [26214-D01-2022].
86 *Ibid* at para 13.

Kainai and Siksika asserted that their spiritual, ceremonial, and cultural rights exercised within the Majorville Cairne and Medicine Wheel area may be adversely impacted by the project.[87] They also raised concerns that there is a high probability of unidentified Blackfoot archaeological sites in the project area that could be impacted or even destroyed by construction. Both First Nations eventually filed letters of non-objection to the project. However, the AUC still considered the adequacy of consultation.[88]

The AUC determined that the duty to consult was triggered and granted full participation rights, including written evidence and an Indigenous knowledge session with Siksika Elders, and access to participant funding so that potential impacts to Aboriginal and treaty rights could be understood and addressed.[89] The project proponents committed to having Blackfoot Traditional Land Use monitors present during construction and to work with Kainai and Siksika if any historic resources are discovered.[90]

The AUC acknowledged that Kainai and Siksika indicated that their project-specific concerns had been addressed, and respected their right to determine the degree to which the project could impact their ability to practice their Aboriginal and treaty rights, and to determine whether their concerns had been adequately addressed.[91] The AUC relied heavily on this in concluding that the duty to consult had been met.[92]

An archeology professor, Dr. Bubel, questioned the adequacy of consultation with the Blackfoot Confederacy, and in particular, the Piikani Nation (Piikani) and the Blackfeet Nation (Blackfeet) in Montana who have a relationship with the Majorville Cairn and Medicine Wheel that predates current borders between Canada and the United States. While she acknowledged that Piikani received notice of the project, Dr. Bubel suggested further consultation was required.[93]

The AUC provided notice to the Piikani, along with other Indigenous groups identified using the Alberta government's Landscape Analysis Indigenous Relations Tool, and followed up multiple times. The AUC was of the view that it provided adequate notice to the Piikani Nation.[94]

The AUC acknowledged that Indigenous groups outside of Canada can have rights within Canada that can trigger the duty to consult. This was confirmed by the Supreme Court of Canada in *R. v. Desautel*.[95] However, the AUC found that there is no freestanding duty on the Crown to seek out Indigenous groups where there is no actual or constructive knowledge of a potential impact on their rights; the Indigenous groups must put the Crown or the AUC on notice that they claim rights in the Canadian territory that may be affected.[96] The AUC also noted that evidence suggesting that individual members of an Indigenous group may

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87 *Ibid* at para 298.
88 *Ibid* at para 300.
89 *Ibid* at para 303.
90 *Ibid* at para 305.
91 *Ibid* at para 309.
92 *Ibid* at para 310.
93 *Ibid* at para 311.
94 *Ibid* at para 312.
95 2021 SCC 17.
96 26214-D01-2022, *supra* note 85 at para 313.

take part in practices or activities does not necessarily mean that the Indigenous group has or claims a collective right protected under section 35 of the *Constitution Act, 1982*.[97] The AUC therefore concluded that the duty to consult with the Blackfeet was not triggered.[98]

D. DEVELOPMENTS IN HONOUR OF THE CROWN AND FIDUCIARY DUTY BEYOND DUTY TO CONSULT

1. *ALTALINK MANAGEMENT LTD. V. ALBERTA (UTILITIES COMMISSION)*

In 2009, the AUC approved AltaLink Management Ltd.'s (AltaLink's) application to expand its transmission system to accommodate the emergence of wind generation in southwest Alberta.[99] The proposed route crossed the Piikani Indian Reserve No. 147 and the Blood Indian Reserve No. 148, and was the shortest and lowest cost route, had no significant environmental impacts, and affected the least number of landowners.[100] The Kainai and Piikani both agreed to the construction of the transmission lines on their reserve lands in exchange for an opportunity to obtain ownership interests in the transmission lines.[101] The AUC approved the proposed route through both reserves.[102]

In 2012 and 2014, the Kainai and Piikani exercised the option to purchase an interest in the transmission lines crossing their reserves.[103] In 2017, AltaLink applied to the AUC to transfer ownership of the transmission lines to new partnerships created with Kainai, KainaiLink Limited Partnership (KainaiLink), and Piikani, PiikaniLink Limited Partnership (PiikaniLink), and those partnerships would become the transmission facility owners for the respective transmission lines.[104]

The AUC approved the transfer, but on the condition that KainaiLink and PiikaniLink could not recover external auditor and hearing costs for regulatory proceedings as part of their rate tariffs.[105] The AUC applied its traditional "no-harm test" to determine whether the transfer was in the public interest, with the primary focus on whether the transfers would impact rates and reliability of service.[106] The AUC was concerned that the additional auditor and hearing costs would increase rates.[107] The AUC viewed the no-harm test as a forward-looking test, and refused to consider the benefits of the selected route, including the costs savings achieved by routing through both reserves.[108] As a result, the AUC concluded that the financial harm from the incremental costs should be mitigated by imposing the condition that those costs could not be recovered from ratepayers.[109]

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97 *Ibid* at para 315.
98 *Ibid* at para 316.
99 *AltaLink Management Ltd v Alberta (Utilities Commission)*, 2021 ABCA 342 at paras 15–17, 24 [*AltaLink Management*].
100 *Ibid* at paras 18, 20.
101 *Ibid* at para 25.
102 *Ibid* at para 24.
103 *Ibid* at para 28.
104 *Ibid* at paras 31–33.
105 *Ibid* at para 34.
106 *Ibid* at paras 35–36.
107 *Ibid* at para 37.
108 *Ibid* at para 39.
109 *Ibid* at para 41.

The Alberta Court of Appeal concluded that the AUC erred in only considering forward-looking benefits when assessing the no-harm test.[110] The Court found that there were lower maintenance costs for the shorter and more accessible route, and the environmental benefits were ongoing, not frozen in the past. The Court found the AUC should not have disregarded these ongoing benefits.[111] A broader view of the no-harm test and the public interest was appropriate.[112]

The Alberta Court of Appeal also held that projects that increase economic activity on First Nations reserves are in the public interest, and should be encouraged.[113] High unemployment rates on reserves is not conducive to a happy and healthy community, and it is not beneficial to Canada to have regions with high unemployment and that lack the benefits of education and employment.[114] Society benefits from a diverse workforce.[115]

The Alberta Court of Appeal therefore held that KainaiLink and PiikaniLink were able to recover audit and hearing costs from ratepayers as part of their tariffs.[116]

2. *MANITOBA MÉTIS FEDERATION INC. V. BRIAN PALLISTER*

In 2014, the Manitoba Métis Federation Inc. (MMF) entered into an agreement, known as the "Turning the Page Agreement" (TPA), with Manitoba Hydro-Electric Board (Manitoba Hydro) and the Government of Manitoba dealing with MMF's objection to certain transmission projects in Manitoba.[117] In accordance with the TPA, MMF and Manitoba Hydro entered into a memorandum of understanding with respect to the Manitoba-Minnesota Transmission Project, and later finalized a draft term sheet called the "Major Agreed Points" (MAP). The province was not part of the discussions that led to the MAP. The MAP contemplated Manitoba Hydro making an initial lump sum payment and further annual payments over 20 years, and additional annualized payments based on estimated capital costs for future projects. In exchange, the MMF would provide Manitoba Hydro with a release for existing transmission projects and future projects undertaken during the initial 20 years of the agreement.[118]

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110 *Ibid* at para 54.
111 *Ibid* at para 55.
112 *Ibid* at para 57.
113 *Ibid* at para 59.
114 *Ibid* at paras 62–63.
115 *Ibid* at para 75.
116 *Ibid* at para 78.
117 *Manitoba Metis Federation Inc v Brian Pallister*, 2021 MBCA 47 at paras 22–23 [*Manitoba Metis Federation*].
118 *Ibid* at paras 24, 26.

MMF viewed the MAP as legally binding, but Manitoba Hydro and the province disagreed.[119] Then on 21 March 2018, the province issued an order in council (OIC) that directed Manitoba Hydro not to proceed with the MAP at that time.[120] The MMF sought a declaration that the province was not acting in accordance with the honour of the Crown, and asked the Court to set aside the OIC.[121]

The Manitoba Court of Appeal concluded that the TPA and the OIC engaged the honour of the Crown for several reasons:

- The honour of the Crown is broad, and the Crown cannot contract out of the honour of the Crown. Contractually giving up certain legal rights may mean that legal remedies grounded in rights may not be available. However, that does not mean that the honour of the Crown does not apply to the agreement.[122]

- One of the main purposes of the TPA was to resolve unaddressed claims and disputes, which triggers the honour of the Crown.[123]

- "[T]he TPA was, at least in part, an accommodation agreement."[124] In addition to resolving certain existing disputes, it set out a framework to resolve future disputes.

- The TPA had the potential to adversely impact the accommodation of rights. "Had the MAP become operational, it would have extended the term of the TPA."[125]

However, the Manitoba Court of Appeal went on to find that the province acted reasonably in the circumstance.[126] Both the province and Manitoba Hydro participated in the TPA resolution process, and it was MMF that ultimately withdrew and advised that it would start legal action. That was when the province issued the OIC and directed Manitoba Hydro not to proceed with the MAP.[127] Even after the OIC was issued, the province and Manitoba Hydro advised that they would continue with the dispute resolution process. The OIC did not preclude a revised version of the MAP.[128] The Court also noted that it is in the public interest for the Crown to act in accordance with the honour of the Crown, but that does not displace the Crown's obligation to take into account the broader public interest.[129] The honour of the Crown does not go so far as to require the Crown to disclose content of Cabinet policy deliberations that are subject to Cabinet privilege.[130]

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119 *Ibid* at para 29.
120 *Ibid* at para 30.
121 *Ibid* at para 11.
122 *Ibid* at para 58.
123 *Ibid* at para 59.
124 *Ibid* at paras 61–62.
125 *Ibid* at para 65.
126 *Ibid* at para 78.
127 *Ibid* at para 79.
128 *Ibid* at para 80.
129 *Ibid* at para 81.
130 *Ibid* at para 83.

Per the Manitoba Court of Appeal, the honour of the Crown also does not include a duty to reach an agreement.[131] The Manitoba Court of Appeal concluded that the province had acted honourably, notwithstanding that no agreement had been reached. It followed the dispute process set out in the TPA. It participated in meetings to resolve the MAP issues. The OIC directed Manitoba Hydro not to proceed with the MAP "at this time," but did not preclude a revised agreement. It sought to have the MAP revised to thoroughly define the adverse effects of projects on the Métis rights and that compensation be required to address a legal obligation. These were not dishonorable or unreasonable.[132] The Supreme Court of Canada denied leave to appeal.[133]

3. *SOUTHWIND V. CANADA*

Southwind v. Canada dealt with a claim for compensation for land taken up for a hydro electric power plant.[134] The dam was built on Lac Seul in 1929, and while the project was a success for several governments, it was devastating for the Lac Seul First Nation (LSFN) and its members, who were deprived of their livelihood, natural resources, and homes.[135] Canada knew that the project would cause significant damage to the LSFN Reserve, but proceeded without compensation or the required authorization.[136] The trial judge concluded that Canada breached its fiduciary duty, and Canada did not dispute this conclusion on appeal.[137]

The issue on appeal was how to assess compensation for the breach.[138] The Supreme Court of Canada found that equitable compensation restores the opportunities the plaintiff lost as a result of the breach of a fiduciary duty and deters wrongdoing by fiduciaries. Equitable principles, including most favourable use, apply to the assessment of compensation.[139] The Supreme Court concluded that the trial judge erred in finding that expropriating the land and paying the minimum statutory obligation would have fulfilled Canada's fiduciary duty. The trial judge erred by focusing on what Canada likely would have done instead of what it should have done as a fiduciary.[140]

The Supreme Court of Canada found that Canada ought to have attempted to negotiate a surrender. Its fiduciary obligations required it to preserve LSFN's quasi-proprietary interest, advance its best interests, and ensure the highest compensation possible. LSFN's interest in the land included an interest in the intended use: a hydroelectric power plant. Canada had an obligation to compensate for that value if the project went forward.[141] Even in an expropriation, Canada was required to secure compensation that reflected the value of the

131 *Ibid* at para 85.
132 *Ibid* at para 87.
133 *Manitoba Metis Federation Inc v Brian Pallister*, 2021 MBCA 47, leave to appeal to SCC refused, 39799 (3 March 2022).
134 2021 SCC 28.
135 *Ibid* at paras 1–2.
136 *Ibid* at paras 3–4.
137 *Ibid* at para 6.
138 *Ibid* at para 9.
139 *Ibid* at para 83.
140 *Ibid* at para 89.
141 *Ibid* at para 112.

land to the project.[142] Equitable compensation must reflect Canada's obligation to ensure that LSFN was compensated for the value of the land to the project.[143]

E. CONCLUSIONS IN ABORIGINAL LAW

The British Columbia Supreme Court's decision on cumulative impacts in *Yahey* is already guiding the government of British Columbia in its efforts to develop a better system to consider cumulative impacts in British Columbia.[144] Whether courts in other jurisdictions adopt the same reasoning remains to be seen, but the *Yahey* decision will certainly be an important consideration in the cumulative impacts claims being advanced in Saskatchewan and Alberta, as well as any further claims advanced in other jurisdictions across Canada.

The duty to consult and accommodate continues to play a key role in administrative decision-making. In *Attawapiskat*, the Ontario Superior Court of Justice confirmed that governments must develop a process that fosters meaningful consultation and provide reasonable time for First Nations to provide information.[145] A failure to do so may ultimately be corrosive to reconciliation. However, First Nations must also take advantage of the time provided, otherwise the courts may not quash the approval in question, even if the duty to consult was not met. Courts have also added to the jurisprudence on what can trigger the duty to consult. In *Ermineskin*, the Federal Court confirmed that economic benefits stemming from impact benefit agreements are closely related to and derived from Aboriginal rights, and can trigger the duty to consult.[146] However, unless parties are willing to introduce evidence about the content of those agreements, tribunals and courts may be limited in their ability to take them into account. Both the AUC and the Supreme Court of Canada have acknowledged that governments may owe a duty to consult with Indigenous groups outside of Canada where the Crown or the regulator has been put on notice that they claim rights within Canada that may be affected by the decision in question.[147]

Recent years have also seen growing reliance on and development of the honour of the Crown beyond the duty to consult. The Alberta Court of Appeal has confirmed that it is in the public interest to increase economic activity on First Nations reserves.[148] The Manitoba Court of Appeal also confirmed that it is in the public interest for the Crown to act in accordance with the honour of the Crown, even if that obligation does not displace the government's obligations to consider the broader public interest, including impacts to non-Indigenous entities and individuals.[149] The Supreme Court of Canada has concluded that compensation for breach of fiduciary duty in taking up of lands must be set in accordance with equitable principles.[150] This means that compensation is based on the value to the development.

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142 *Ibid* at para 113.
143 *Ibid* at para 143.
144 *Supra* note 27.
145 *Supra* note 59.
146 *Supra* note 76.
147 26214-D01-2022, *supra* note 85 at para 313; *R v Desautel*, *supra* note 95.
148 *AltaLink Management*, *supra* note 99 at para 59.
149 *Manitoba Metis Federation*, *supra* note 117 at para 81.
150 *Southwind v Canada*, *supra* note 134 at para 143.

Government policies are increasingly looking to further reconciliation and encourage Indigenous participation. Industry is similarly looking to partner with Indigenous groups in new ways. This is something we expect to continue, and the relationships between governments, industry, and Indigenous groups will continue to become more and more important. The developing case law can help guide parties in their dealings and help build relationships. However, the number of developments and cases in recent years shows that parties are at times, still struggling to find the right path forward.

IV. OIL AND GAS

Environmental goals have also dominated developments in the oil and gas industries with stronger liability management frameworks to address concerns about the growing number of inactive wells awaiting reclamation. Jurisdictions in Canada are divided on the future of oil and gas in the country, with Newfoundland and Labrador looking to increase drilling, particularly offshore drilling, and Quebec looking to bring an end to production of petroleum products in the province. Finally, the Government of Alberta has continued to fight for its ability to regulate the export of oil and gas (or "turn off the tap"), without actually taking steps to do so.

A. LIABILITY MANAGEMENT

The Alberta liability management for oil and gas has undergone significant changes in recent years. The Government of Alberta announced a new "liability management framework" in July 2020 and directed the AER to implement the policy.[151] The AER is adopting a holistic approach, designed to apply at each phase and not simply to focus on the late stages in the lifecycle of energy developments.[152]

On 1 December 2021, the AER's new Directive 088 (Life-Cycle Management)[153] and Manual 23: Licensee Life-Cycle Management came into effect,[154] along with amendments to Directive 006 (Licencee Liability Rating (LLR) Program)[155] and Directive 013 (Suspension Requirements for Wells).[156] The new Directive 088 introduces mandatory closure spend targets and updates requirements related to the licence transfer process.[157] A

151 Alberta, "Oil and Gas Liabilities Management," online: <www.alberta.ca/oil-and-gas-liabilities-management.aspx>.

152 Alberta Energy Regulator, "Liability Management," online: <www.aer.ca/providing-information/by-topic/liability-management>.

153 Alberta Energy Regulator, *Directive 088: Licensee Life-Cycle Management* (Calgary: Alberta Energy Regulator, 1 December 2021), online: <static.aer.ca/prd/documents/directives/Directive088.pdf>.

154 Alberta Energy Regulator, *Manual 023: Licensee Life-Cycle Management* (Calgary: Alberta Energy Regulator, 3 May 2022), online: <static.aer.ca/prd/documents/manuals/Manual023.pdf>.

155 Alberta Energy Regulator, *Directive 006: Licensee Liability Rating (LLR) Program* (Calgary: Alberta Energy Regulator, 1 December 2021), online: <static.aer.ca/prd/documents/directives/Directive 006_0.pdf.

156 Alberta Energy Regulator, *Directive 013: Suspension Requirements for Wells* (Calgary: Alberta Energy Regulator, 1 December 2021), online: <static.aer.ca/prd/documents/directives/Directive013.pdf>.

157 Alberta Energy Regulator, *Bulletin 2021-45: New Requirements and Guidance Related to Liability Management* (Calgary: Alberta Energy Regulator, 1 December 2021), online: <static.aer.ca/prd/documents/bulletins/Bulletin-2021-45.pdf>.

more in-depth discussion on Alberta's liability management can be found in the article by Jeff Davidson, Jeremy Barretto, Tamara Prince, Chris McLelland, and Alyshea Surani.[158]

British Columbia is also in a transition period with respect to liability management. The British Columbia Oil and Gas Commission (BCOGC) is enhancing checks of companies' financial health with the introduction of a permittee capability assessment (PCA) with the goal of mitigating liability risk and minimizing pressure on the orphan site reclamation fund.[159] The PCA will assess corporate health against liabilities associated with dormant, inactive, and marginal sites to determine corrective action requirements, which may include additional security requirements or closure work. The BCOGC gradually moved from the previous liability management rating program to the PCA, with full implementation on 1 April 2022.[160]

B. *AN ACT MAINLY TO END PETROLEUM EXPLORATION AND PRODUCTION AND THE PUBLIC FINANCING OF THOSE ACTIVITIES*

The Government of Quebec passed legislation on 12 April 2022 aimed at putting an end to exploration for, and production of, oil and gas.[161] Bill 21 will prohibit exploration for storing or producing petroleum (defined to include both oil and gas) or brine;[162] revoke exploration and production licences;[163] impose closure obligations on holders of revoked licences;[164] and establish a compensation program for expenses incurred between 19 October 2015 and 19 October 2021, including expenses relating to the acquisition of the licence, compliance with prior legislation, and up to 75 percent of permanent well closure and site restoration costs.[165]

Bill 21 allows for pilot projects for the purpose of obtaining geoscience knowledge related to carbon dioxide sequestration potential, storage for hydrogen produced from a source of renewable energy, deep geothermal potential, the storage and strategic mineral potential of brine, and other activities that encourage the energy transition or helps to fight climate change.[166]

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158 Jeremy Barretto et al, "Leading the Way? Liability Management for the Alberta Oil and Gas Industry" (2022) 60:2 Alta L Rev 487.

159 BC Oil and Gas Commission, "Liability Management," online: <www.bcogc.ca/energy-professionals/operations-documentation/liability-management/>.

160 BC Oil and Gas Commission, "Implementing Permittee Capability Assessment (INDB 2022-05)" (16 February 2022), online: <www.bcogc.ca/news/implementing-permittee-capability-assessment-indb-2022-05/>.

161 Bill 21, *An Act mainly to end petroleum exploration and production and the public financing of those activities*, 2nd Sess, 42nd Leg, Quebec, 2022 (assented to 13 April 2022), SQ 2022, c 10.

162 *Ibid*, s 6.

163 *Ibid*, s 7.

164 *Ibid*, s 10.

165 *Ibid*, ss 32–41.

166 *Ibid*, s 43.

C. NEWFOUNDLAND AND LABRADOR OFFSHORE EXPLORATION INITIATIVE

The Government of Newfoundland and Labrador is taking a different approach, and is expanding eligibility for its Offshore Exploration Initiative, which commenced in 2021 and will continue until 2024.[167] The Offshore Exploration Initiative is designed to fund a certain percentage of well costs beyond the first well drilled on a licence.

The provincial Minister of Industry, Energy and Technology announced on 30 December 2021 that it was extending the eligibility to include wells spudded up to 31 December 2023 (previously 31 December 2022).[168]

The Canada-Newfoundland and Labrador Offshore Petroleum Board is also poised to become the Canada-Newfoundland and Labrador Offshore Energy Board.[169]

D. BAY DU NORD

On 6 April 2022, the federal government approved Equinor Canada Limited's Bay du Nord project.[170] The project would use a floating production unit for storage and offshore offloading.[171] This project aligns with the Government of Newfoundland and Labrador's goals of encouraging offshore oil and gas development. However, the decision has been criticized by some environmental groups.

The federal Minister of Environment and Climate Change Canada determined that the project is not likely to cause significant adverse environmental effects.[172] The approval is subject to 137 conditions, including: ongoing consultation; annual reporting; fish habitat surveys; developing and implementing monitoring plans for marine life and birds; incorporating greenhouse gas and air emission reduction measures; having no CO2 emissions by 1 January 2050; undertaking a spill impact mitigation assessment; and developing a spill response plan.

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167 Industry, Energy and Technology, "Offshore Exploration Initiative," online: <www.gov.nl.ca/iet/funding/offshore-exploration-incentive/>.

168 Industry, Energy and Technology, News Release, "Offshore Exploration Initiative Eligibility Amendment" (30 December 2021), online: <www.gov.nl.ca/releases/2021/iet/1230n02/>.

169 Natural Resources Canada, News Release, "Canada and Newfoundland and Labrador Announce Intent to Expand the Mandate of Offshore Energy Regime to Support the Transition to a Clean Economy and Create Sustainable Jobs" (5 April 2022), online: <www.canada.ca/en/natural-resources-canada/news/2022/04/canada-and-newfoundland-and-labrador-announce-intent-to-expand-the-mandate-of-offshore-energy-regime-to-support-the-transition-to-a-clean-economy-a.html>.

170 Impact Assessment Agency of Canada, News Release, 84, "Government Accepts Agency's Recommendation on Bay du Nord Development Project, Subject to the Strongest Environmental GHG Condition Ever" (6 April 2022), online: *Government of Canada* <iaac-aeic.gc.ca/050/evaluations/document/143501?culture=en-CA>.

171 "The Bay du Nord Project," online: *Equinor* <www.equinor.com/en/where-we-are/canada-bay-du-nord.html>.

172 *Re Decision Statement Issued under Section 54 of the* Canadian Environmental Assessment Act, 2012 (6 April 2022), online: Impact Assessment Agency of Canada <iaac-aeic.gc.ca/050/documents/p80154/143500E.pdf>.

E. ALBERTA'S CONTINUED EFFORTS TO "PRESERVE CANADA'S ECONOMIC PROSPERITY"

In 2018, the Government of Alberta passed the *Preserving Canada's Economic Prosperity Act*,[173] which gave the Alberta Minister of Energy sweeping powers to control the export of natural gas, crude oil, and refined fuels from Alberta using export licences. The *PCEPA* 2019, affectionately (or not so affectionately) known as the "turn off the taps legislation" was proclaimed on 30 April 2019, one of the first acts of the newly elected United Conservative Party government.

The Government of British Columbia wasted no time in challenging the constitutionality of the legislation. However, the claim was struck down by the Federal Court of Appeal on 26 April 2021.[174] The majority held that the statutory devices required to make the *PCEPA* 2019 operative (such as a licencing scheme put in place by regulations) was not yet in place, and so a dispute giving rise to declaratory relief had not yet arisen, and may never arise.

However, the *PCEPA* 2019 stated that it was automatically repealed two years after it came into force, and it was repealed on 30 April 2021. Less than a month later, on 25 May 2021, the Government of Alberta tabled a new bill, also called the *Preserving Canada's Economic Prosperity Act*.[175] The Government of Alberta said that the *PCEPA* 2021 had been strengthened to withstand constitutional challenge. Unlike the *PCEPA* 2019, the *PCEPA* 2021 does not apply to refined fuels. Section 92A(2) of the *Constitution Act, 1867* gives provinces the jurisdiction to make laws regarding the export of the *primary production* from non-renewable natural resources.[176] The removal of refined fuels may make the legislation better fit within that section, but Alberta will still have to face arguments that the *PCEPA* 2021 is discriminatory against other provinces (if it ever tries to implement the proposed export scheme). The *PCEPA* 2021 received royal assent on 17 June 2021, but came into force retroactively on 1 May 2021.

Alberta still has not made the regulations necessary to implement the licencing system. It remains to be seen whether Alberta will do so, and if it does, whether attempts to strengthen the constitutionality of the legislation will be successful.

V. PIPELINES

The long-running Keystone XL pipeline saga continues. In February 2022, Alberta launched an investment arbitration suit under the North American Free Trade Agreement's investor protection provisions.[177] Alberta seeks $1.3 billion as compensation for President

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173 SA 2018, c P-21.5 [*PCEPA* 2019].

174 *Attorney General of Alberta v Attorney General of British Columbia*, 2021 FCA 84.

175 Bill 72, *Preserving Canada's Economic Prosperity Act*, 2nd Sess, 30th Leg, Alberta, 2021 (assented to 17 June 2021), SA 2021, c P-21.51 [*PCEPA* 2021].

176 *Constitution Act, 1867* (UK), 30 & 31 Vict, c 3, s 92A(2), reprinted in RCS 1985, Appendix II, No 5.

177 These provisions continue to apply until 1 July 2023 under the terms of the *Canada-United States-Mexico Agreement*, 30 November 2018 (entered into force 1 July 2020) [*CUSMA*], online: <www.international.gc.ca/trade-commerce/trade-agreements-accords-commerciaux/agr-acc/cusma-aceum/text-texte/toc-tdm.aspx?lange=eng&lang=eng>: see Global Affairs Canada, *Canada-United States-Mexico Agreement (CUSMA) – Chapter 14 – Investment*, online: <www.international.gc.ca/trade-commerce/trade-agreements-accords-commerciaux/agr-acc/cusma-aceum/text-texte/14.aspx?lang=eng>.

Joe Biden's cancellation of the presidential permit that authorized the Keystone XL pipeline to cross the border from Canada to the US.

The case is the first time one level of government has started an action, as an investor, against another government under these investor protections.[178] TC Energy also filed its own investor protection case last year.

The trend of Indigenous groups purchasing equity interests in energy infrastructure projects also continues. On 9 March 2022, TC Energy announced the signing of option agreements to sell a 10 percent equity interest in the Coastal GasLink Pipeline Limited Partnership to Indigenous communities across the project corridor. TC Energy gave all 20 Indigenous groups holding agreements with Coastal Gas Link the option to purchase equity and at the time of the announcement, 16 of the 20 Indigenous communities had agreed to do so.[179]

Apart from these continuing trends, there were two significant decisions from the Canadian Energy Regulator (CER) over the past year on traffic, toll, and tariff matters. These decisions are discussed in the following sections of this article.

A. ENBRIDGE MAINLINE FIRM CONTRACTING DECISION

One of the most notable decisions of the CER Commission over the past year was its decision to deny Enbridge Pipelines Inc.'s (Enbridge's) application for a new service and tolling framework on its Canadian Mainline pipeline system.[180] If approved, that framework would have allowed shippers to sign long-term contracts for up to 90 percent of the Mainline's capacity.[181]

Enbridge's Mainline is the only major Canadian oil pipeline to operate entirely as a common carrier, with all of its capacity available for nomination on a short-term basis. This contrasts with other major Canadian oil pipelines that allow shippers to make long-term firm commitments to the pipeline.

Enbridge's application was supported by refiners and integrated oil producers with refineries on Enbridge's system or on downstream connecting pipelines.[182] Enbridge contended that long-term firm contracting would de-risk the Mainline, enable potential future expansion, and reduce risks associated with upstream and downstream investment decisions.

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178 Lawrence Herman, "Alberta Breaks New Ground in its Keystone Appeal" (25 February 2022), online: *CD Howe Institute* <www.cdhowe.org/intelligence-memos/lawrence-herman-alberta-breaks-new-ground-its-keystone-appeal>.

179 TC Energy, News Release, "TC Energy Signs Equity Option Agreements with Indigenous Communities Across the Coastal GasLink Project Corridor" (9 March 2022), online: <www.tcenergy.com/announcements/2022-03-09-tc-energy-signs-equity-option-agreements-with-indigenous-communities-across-the-coastal-gaslink-project-corridor/>.

180 *Canadas Energy Regulator Reasons for Decision: Enbridge Pipelines Inc* (November 2021), RH-001-2020, online (pdf): CER <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/155829/3773831/3890507/4038614/4167013/C16317-1_Commission_-_Canada_Energy_Regulator_Reasons_for_Decision_RH-001-2020_%E2%80%93_Enbridge_Pipelines_Inc._%E2%80%93_Canadian_Mainline_Contracting_-_A7Y9R1.pdf?nodeid=4166515&vernum=-2> [*RH-001-2020*].

181 *Ibid* at 6.

182 *Ibid* at 11.

Enbridge further noted that having parties with refining interests make long-term capacity commitments on the Mainline, would lock in oil markets to the benefit of western Canadian producers.[183]

The CER Commission found that such a high-level of firm contracting was inconsistent with Enbridge's common carrier obligation.[184] In making this finding, the CER Commission made it clear that oil pipelines are not required to maintain 100 percent of their capacity for uncommitted service.[185] Instead, it continued to adopt a pragmatic and purposive approach to an oil pipeline's common carriage obligation. It found that the common carriage obligation requires the CER Commission to "ensure that access to oil pipelines be reasonably preserved at all times and allows the Commission to consider alternatives to 100 per cent uncommitted capacity both on new and existing infrastructure."[186]

Historically, the CER and its predecessor found that the statutory common carrier requirement could be satisfied where an oil pipeline company conducted a reasonable open season for firm contract service and left some capacity available to shippers for uncommitted service.[187] Typically, these firm service applications were filed to support the construction of a new pipeline system or the expansion of an existing system.[188]

The CER Commission observed that removing 90 percent of uncommitted capacity on Enbridge's Mainline for periods of up to 20 years would have negative effects on overall access to the Mainline without a compelling justification.[189] The CER Commission identified that Enbridge's application, if approved, risked potentially significant disruptions to the market of unknown duration without any reliable way to respond to and mitigate such impacts in a timely manner.[190] The CER Commission also noted that Enbridge did not require the firm contracts to backstop new facilities that would enhance capacity.[191]

The decision is welcome news for smaller shippers that may not have financial capacity to backstop a long-term firm transportation contract on Enbridge's Mainline, or shippers that may not want to commit to long-term firm service.

The decision, however, places Enbridge's Mainline at a competitive disadvantage compared to other oil pipelines out of the Western Canada Sedimentary Basin (WCSB). While at the time of the decision it was expected that some level of supply risk may materialize in the short-term when Enbridge's Line 3 replacement project and the Trans Mountain expansion come into service,[192] post-decision events such as the war in Ukraine

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183 *Ibid* at 46.
184 *Ibid* at 68. See also *Canadian Energy Regulator Act*, SC 2019, c 28, s 239 [*CER Act*].
185 *RH-001-2020*, *supra* note 180 at 30.
186 *Ibid* at 20.
187 *Ibid* at 19.
188 See e.g. *Reasons for Decision - Trans Mountain Pipeline ULC on behalf of Trans Mountain Pipeline, LP* (December 2011), RH-2-2011, online (pdf): NEB <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/552980/954147/655087/768172/768253/A37359-1_NEB_Reasons_for_Decision_-_Trans_Mountain_-_Firm_Service_to_Westridge_Marine_Terminal_-_RH-2-2011.pdf?nodeid=768090&vernum=-2> [*RH-2-2011*].
189 *RH-001-2020*, *supra* note 180 at 2.
190 *Ibid*.
191 *Ibid* at 30.
192 *Ibid* at 26.

and resulting energy supply recalibration likely eliminate or diminish the extent of the Mainline's short-term supply risk. Nonetheless, without some level of firm contracting, the Enbridge Mainline will continue to be the swing oil pipeline out of the WCSB, exposing the pipeline to the realization of supply risk in the medium or long-term.

Given these risks, and because of some of the positive signals expressed by the CER Commission — the CER Commission acknowledged that "many Enbridge submissions had merit and that elements of the Application provided a strong justification for some firm service" — there is an opportunity for Enbridge to firm up some of its existing capacity through a new application.[193] Whether Enbridge will make such an application, in what has suddenly turned into a lower supply risk environment, is an open question.

B. TRANS MOUNTAIN FIRM CONTRACTING RENEWAL

An interesting contrast to the Enbridge firm contracting decision is the CER Commission's decision to renew firm contracting on Trans Mountain's pipeline system, released just five days after the Enbridge decision.[194] In its *RH-2-2011* decision,[195] the CER's predecessor approved firm contracting on the Trans Mountain pipeline system with service to the Westridge Marine Terminal for a small portion of the total pipeline capacity (18 percent), approximately 54,000 bpd, with the majority of capacity remaining available for uncommitted service (82 percent), including approximately 30 percent of the pipeline's capacity for deliveries to the Westridge Marine Terminal. Unlike the Enbridge decision, the renewal application was approved with very brief reasons, likely because it was unopposed by Trans Mountain's shippers.

C. NORTH MONTNEY FIRM TRANSPORTATION LINKED SERVICE

On 19 January 2022, the CER Commission denied an application from NOVA Gas Transmission Limited (NGTL) for its proposed firm transportation linked service on its North Montney Mainline.[196] The service would provide linked receipt services from the North Montney Mainline in Northeast BC to the proposed Willow Valley interconnect delivery point, which would serve the Coastal GasLink pipeline. The service was designed to attract PETRONAS Energy Canada Ltd. (PETRONAS) volumes to the NGTL system. The

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193 *Ibid* at 2.

194 Canada Energy Regulator, Letter, "Trans Mountain Pipeline ULC on behalf of Trans Mountain Pipeline L.P.: Application for Approval of Firm Service Recontracting (Application)" (1 December 2021), online (pdf): <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/552980/4083831/4107481/4166623/C16346-1_Letter_to_Trans_Mountain_Pipeline_ULC_-_Application_for_Approval_of_Firm_Service_Recontracting_-_A7Y9Z7.pdf?nodeid=4167340&vernum=-2>.

195 *RH-2-2011*, *supra* note 188.

196 Canada Energy Regulator, Letter, "NOVA Gas Transmission Ltd.: Application for Firm Transportation – Linked North Montney Service (FT-L (NM) Service) (Application) – RH-001-2021 Decisions with Reasons to Follow" (19 January 2022), online (pdf): <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92833/554137/4096416/4097061/4096505/4200121/C17285-1_Commission_%E2%80%93_Letter_%E2%80%93_NOVA_Gas_%E2%80%93_Application_for_Firm_Transportation_%E2%80%93_Linked_North_Montney_Service_%E2%80%93_RH-001-2021_%E2%80%93_Decisions_with_reasons_to_follow_-_A8A3E6.pdf?nodeid=4200122&vernum=-2>.

CER Commission found that the Westcoast system was a credible and viable alternative to service on NGTL, such that PETRONAS' volumes could bypass the NGTL system.[197]

The decision is significant for detailing the CER Commission's framework for examining tolling methodologies between competitive pipelines and whether a load retention or attraction toll is appropriate, among other things. The decision also builds upon prior decisions of the Commission and its predecessor regarding the appropriate tolling methodology for NGTL's Northeast BC assets, including the tolling methodology for the receipt of gas in Northeast BC for delivery to NGTL's affiliated Coastal GasLink pipeline.[198] This issue will almost certainly resurface in the future.

The CER Commission confirmed that a load attraction or retention service could be appropriate, even on fully contracted pipelines such as the North Montney Mainline, where competitive risks have not been realized. The CER Commission found that the firm transportation linked service was developed in response to a credible competitive threat[199] and that it was appropriate for NGTL to develop a specialized service for liquified natural gas volumes when it was clear that its current service offerings were uncompetitive.[200] Prior CER Commission decisions, and decisions of its predecessor, involving load attraction or retention services generally involved pipelines where competitive risks had been realized or would soon be realized (e.g. where the pipeline was underutilized).[201]

In denying NGTL's proposed service offering, the CER Commission re-emphasized the primacy of cost-based tolling principles and that departures from the cost-based principles must be strongly justified. The CER Commission found that NGTL failed to establish that its proposal was consistent with *CER Act* requirements that tolls be just and reasonable, and not unjustly discriminatory.[202] In reaching these findings, the CER Commission noted that:

197 *Canadas Energy Regulator Reasons for Decision: NOVA Gas Transmission Ltd* (March 2022), RH-001-2021 at 21, online (pdf): CER <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92833/554137/4096416/4097061/4096505/4239905/C18261-1_Commission_%E2%80%93_Reasons_for_Decision_RH-001-2021_%E2%80%93_NOVA_Gas_%E2%80%93_Application_for_Firm_Transportation_%E2%80%93_Linked_North_Montney_Service_-_A8C7C1.pdf?nodeid=4240085&vernum=-2> [*RH-001-2021*].

198 *Ibid* at 6.

199 *Ibid* at 21.

200 *Ibid* at 22.

201 See e.g. *Letter Decision: TransCanada PipeLines Limited (TransCanada): Application for Approval of Herbert Long Term Fixed Price (Herbert LTFP) Service* (5 July 2017), RH-002-2017, online (pdf): NEB <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92833/92843/3119193/3119634/3173691/3299726/A84788-1_NEB_%E2%80%93_Letter_Decision_%E2%80%93_TransCanada_%E2%80%93_Herbert_LTFP_%E2%80%93_RH-002-2017_-_A5R9Z2.pdf?nodeid=3297310&vernum=-2>; *Letter Decision: TransCanada PipeLines Limited (TransCanada): Application for Approval of Dawn Long Term Fixed Price (Dawn LTFP) Service* (23 November 2017), RH-003-2017, online (pdf): NEB <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92833/92843/3119193/3224371/3224033/3391730/A88125-1_NEB_%E2%80%93_Reasons_for_Decision_%E2%80%93_TransCanada_%E2%80%93_Dawn_LTFP_%E2%80%93_RH-003-2017_-_A5X5F6.pdf?nodeid=3392584&vernum=-2>; *Letter Decision: TransCanada PipeLines Limited (TransCanada): North Bay Junction Long Term Fixed Price (NBJ LTFP) Service* (13 June 2019), RH-002-2018, online (pdf): NEB <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92833/92843/3646690/3715883/3773274/3785045/A99955-1_NEB_%E2%80%93_Letter_Decision_with_Reasons_for_Decision_RH-002-2018_%E2%80%93_TransCanada_%E2%80%93_North_Bay_Junction_LTFP_-_A6V2K0.pdf?nodeid=3785440&vernum=-2>.

202 *RH-001-2021*, *supra* note 197 at 23.

- The proposed tolls failed to meet the cost causation principle because they were primarily designed to recover incremental costs and not the embedded cost of service of the existing system, resulting in the potential for inappropriate cross-subsidization.[203]

- There was an inappropriate shift of risk related to possible future cost overruns from PETRONAS to existing shippers.[204]

- Any future net benefit (which was in any event modest) connected with the service was uncertain, particularly if future costs were higher than forecast.[205]

There will likely be future applications dealing with tolling methodology on the North Montney Mainline in the near future. The CER Commission denied NGTL's request to affirm the continued use of the existing North Montney Mainline tolling methodology for existing services that utilize the North Montney mainline when gas deliveries start at the Willow Valley interconnect delivery point for transport on the Coastal GasLink Pipeline.[206] Accordingly, NGTL will return to the CER Commission before those volumes start to flow.

VI. POWER

One of the key decarbonization strategies is increased electrification, where electricity (especially "clean" electricity) displaces emitting energy sources. Key developments include: the Government of Alberta signaling an intent to allow increased self-supply and export and development of energy storage; Manitoba returning power to the Manitoba Public Utilities Board to set rates through full public hearings; the Government of Ontario investigating opportunities for further hydroelectric developments in northern Ontario, with opportunities to partner with northern and Indigenous communities; the Governments of Ontario, New Brunswick, Saskatchewan, and Alberta moving forward with investigating the possibility of small modular nuclear reactors; and the Government of Newfoundland and Labrador releasing its renewable energy plan to increase development of renewable resources in the province, including investigating opportunities for export and development of hydrogen.

A. (ALMOST) ALLOWING SELF-SUPPLY AND EXPORT AND ENERGY STORAGE IN ALBERTA

On 17 November 2021, the Government of Alberta introduced Bill 86: *Electricity Statutes Amendment Act, 2021*.[207]

One of the notable features of this bill is that it would allow parties to build generation to serve their own needs, and export the surplus to the grid. The AUC had previously held that

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203 *Ibid* at 29.
204 *Ibid* at 31.
205 *Ibid* at 31–32.
206 This issue was contemplated by Condition 2 of *Order TG-002-2020* (25 March 2020), online (pdf): CER <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92833/554137/ 3752363/3752364/3760156/ 3913151/C05448-5_CER_%E2%80%93_Order_TG-002-2020_%E2%80%93_NOVA_Gas_%E2% 80%93_NGTL_System_Rate_Design_and_Services_-_A7E4T2.pdf?nodeid=3913155&vernum=-2>.
207 Bill 86, *Electricity Statutes Amendment Act, 2021*, 2nd Sess, 30th Leg, Alberta, 2021 [Bill 86].

the generation either had to be used entirely for self-supply, or entirely supplied to the grid,[208] so this was a welcome change for industry. However, the bill would also make self-supply subject to a tariff to pay for a just and reasonable share of costs associated with the transmission system, a less welcome change for industry, but some comfort to ratepayers.

The bill also clarified murky issues related to the use of energy storage, including setting out the circumstances under which distribution and transmission utilities can, and cannot, own energy storage. There is currently one distribution facility owner, FortisAlberta Inc., with energy storage in Alberta. The AUC approved the project in January 2021.[209] The energy storage was built to provide temporary backup in Waterton in the event that it is disconnected from the Alberta interconnected electric system.[210] The AUC did not explicitly address whether transmission and distribution facility owners should own energy storage facilities, but did note that the project would not export energy to the power pool. The AUC also noted that it expected FortisAlberta Inc. to comply with any future legislation that affects its ownership of energy storage.[211]

Under Bill 86, transmission facility owners could own energy storage that has been included in a needs identification document,[212] but may not sell the electric energy from energy storage into the power pool.[213] Distribution facility owners require approval from the AUC to operate energy storage facilities. The AUC must consider any economic alternatives, including whether it is economic to procure non-wire services competitively.[214] This is one of several issues that electric distribution utilities and the AUC are wrestling with as they determine the best way to modernize the grid to accommodate the changing ways in which electricity is produced, transported, and consumed.

Bill 86 would also require distribution facility owners to prepare distribution system plans in accordance with any ministerial regulations.[215]

However, despite passing second reading on 24 November 2021, Bill 86 did not pass third reading before the second session ended. The 22 February 2022 throne speech confirmed that new legislation will be introduced to solidify Alberta as a modern electricity powerhouse, so stay tuned for changes to see how these issues will be addressed in 2022.[216]

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208 Nigel Bankes, "The Implications of the AUC's *Smith* Decision" (18 June 2019), online (blog): <ablawg.ca/2019/06/18/the-implications-of-the-aucs-smith-decision/>.

209 *FortisAlberta Inc.: Waterton Battery Energy Storage System* (15 January 2021), 26101-D01-2021, online (pdf): AUC <efiling-webapi.auc.ab.ca/Document/Get/683303>.

210 *Ibid* at paras 4–5.

211 *Ibid* at para 13.

212 In Alberta, there is a two-step process for increasing transmission capacity, although in practice, the two steps can occur in the same proceeding: *Electric Utilities Act*, SA 2003, c E-5.1, ss 34– 35. First, the Alberta Electric System Operator must identify a need for increased transmission capacity and apply to the AUC for a "needs identification document" setting out the need. Then, the transmission facility operator must apply to the AUC to construct and operate the transmission facilities that will meet the identified need.

213 Bill 86, *supra* note 207, s 2(8).

214 *Ibid*, s 3(11).

215 *Ibid*, s 2(10)(ii)(a.1).

216 Government of Alberta, News Release, "Speech from the Throne: February 22, 2022" (22 February 2022), online: <www.alberta.ca/release.cfm?xID=819455A1603F4-C503-01A1-7838E7FCB3216C79>.

The Government of Alberta subsequently introduced and passed Bill 22, which incorporated many of the same provisions.[217] In addition, it allows the AUC to grant industrial system designation to certain self-supply generation that was in service before 1 January 2022.[218] This will allow those operations to avoid the tariff applicable to self-supply. Bill 22 is expected to be proclaimed in force at the same time as related regulations are brought into force.[219]

B. A RETURN TO RATE HEARINGS FOR MANITOBA HYDRO

In 2020, the Government of Manitoba proposed legislation that would suspend public rate hearings for Manitoba Hydro until 2024, at which point the Public Utilities Board (PUB) would resume approving electricity rates, but for a five-year period, instead of holding expensive hearings annually.[220]

However, in September 2021, the Government of Manitoba announced that it was not proceeding with the proposed legislation, and directed Manitoba Hydro to apply to the PUB for interim rates and to engage with the PUB on submitting multi-year rate applications.[221] In March 2022, the province affirmed its commitment to multi-year rates and introduced Bill 36 that would introduce three-year rate periods,[222] and limit increases to the lesser of 5 percent or the rate of inflation starting in 2025.[223] Bill 36 also allows entities other than Manitoba Hydro to become involved in retail supply of power,[224] a move that the opposition has said could lead to a partial privatization of Manitoba Hydro.[225]

C. ONTARIO POWER GENERATION TO INVESTIGATE HYDROELECTRIC OPPORTUNITIES

The Government of Ontario has asked Ontario Power Generation (OPG) to investigate opportunities for new hydroelectric generation in northern Ontario to address growing electricity needs, with potential benefits to local and Indigenous communities in the north.[226] OPG will evaluate hydroelectric opportunities with estimates of water availability, energy production potential, and life cycle costs of building and operating new hydroelectric generation. OPG will share this work with the Ontario Ministry of Energy and the

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217 Bill 22, *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act, 2022*, 3rd Sess, 30th Leg, Alberta, 2022 [Bill 22].

218 *Ibid*, s 3(4)(a).

219 Government of Alberta, News Release, "Modernizing Alberta's Electricity System" (2022), online: <www.alberta.ca/ modernizing-albertas-electricity-system.aspx>.

220 Ian Froese, "Manitobans Would Temporarily Lose Public Hearings on Hydro Rates under New Law," *CBC News* (20 March 2020), online: <www.cbc.ca/news/canada/manitoba/manitoba-hydro-rates-new-bill-manitoba-government-1.5504868>.

221 Government of Manitoba, News Release, "Department of Crown Services Issues Directive to Manitoba Hydro to Submit Rate Application" (22 September 2021), online: <news.gov.mb.ca/news/index.html?item=52527&posted=2021-09-22>.

222 Bill 36, *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act*, 4th Sess, 42nd Leg, Manitoba, 2022, s 13 [Bill 36].

223 *Ibid*.

224 *Ibid*, s 5(2).

225 Steve Lambert, "Manitoba Hydro Rate Increases Could Be Capped, Hearings Reduced under New Bill," *The Canadian Press* and *CTV News Winnipeg* (22 March 2022), online: <winnipeg.ctvnews.ca/manitoba-hydro-rate-increases-could-be-capped-hearings-reduced-under-new-bill-1.5829982>.

226 Government of Ontario, News Release, "Province Asking Ontario Power Generation to Investigate New Hydroelectric Opportunities" (20 January 2022), online: <news.ontario.ca/en/release/1001449/province-asking-ontario-power-generation-to-investigate-new-hydroelectric-opportunities>.

Independent Electricity System Operator (IESO) so that it can be considered in the IESO's work towards developing the pathway to a zero-emission electricity sector. OPG has been asked to specifically engage with Indigenous communities to understand how Indigenous communities could participate in and benefit from future hydroelectric generation projects.

D. SMALL MODULAR NUCLEAR REACTORS

In April 2021, the Government of Alberta became the fourth province to sign a memorandum of understanding (MOU) on small modular nuclear reactors (SMRs), joining New Brunswick, Ontario, and Saskatchewan.[227] On 28 March 2022, the provinces announced a strategic plan on SMRs that highlights how SMRs can provide safe, reliable, and zero-emissions energy to meet growing demands.[228] The report identifies five key priorities for SMR development and deployment:[229]

- Positioning Canada as an exporter of SMR technology by propelling three separate streams of SMR development,[230] covering both on-grid and off-grid applications.

- Promoting a strong nuclear regulatory framework that focuses on the health and safety of the public and the environment while ensuring reasonable costs and timelines.

- Securing commitments from the federal government on financial and policy support for new SMR technologies.

- Creating opportunities for participation from Indigenous communities and public engagement.

- Working with the federal government and nuclear operators on a robust nuclear waste management plan for SMRs.

The MOU provinces will continue to seek opportunities for collaboration on SMR advancement with the federal government to ensure the necessary financial, regulatory, and policy supports are in place to support SMR development.

227 Government of Alberta, News Release, "Alberta Signs Small Modular Nuclear Reactor MOU" (14 April 2021), online: <www.alberta.ca/release.cfm?xID=779532BE17742-9A86-61A0-8EE237BE8A6450E0>.

228 Government of Alberta, News Release, "Small Modular Reactors: Provinces Release Strategic Plan" (28 March 2022), online: <www.alberta.ca/release.cfm?xID=822102CB336A7-045D-908F-456B5 DE51633 CB7E>.

229 Governments of Ontario, New Brunswick, Alberta & Saskatchewan, *A Strategic Plan for the Deployment of Small Modular Reactors* (2022) at 10–23, online: <open.alberta.ca/dataset/de9ebaba-81a7-456e-81a2-2c57cb11412e/resource/62319fa5-aa5a-4329-b980-5c85a924c7c7/download/energy-interprovincial-strategic-plan-deployment-of-smrs-2022.pdf>.

230 A 300 megawatt grid-scale SMR project in Ontario by 2028; two advanced SMRs in New Brunswick in 2029 and 2030; and a new class of micro-SMRs designed to replace diesel in remote communities.

E. NEWFOUNDLAND AND LABRADOR RENEWABLE ENERGY PLAN

In December 2021, the Government of Newfoundland and Labrador released its Renewable Energy Plan.[231] Eighty percent of the province's electricity is already generated from renewable resources, which is expected to increase to 98 percent when the Muskrat Falls components of the Lower Churchill Hydroelectric Project is fully commissioned and the oil-fired Holyrood Thermal Generation Station is closed.[232] Muskrat Falls was expected to be fully complete by 26 November 2021, but difficulties with the control and protection software in both 2021[233] and 2022 have delayed final commissioning.[234] The software is currently being tested, and if tests are successful, commissioning could be finalized by the end of this year.[235]

Undeveloped renewable resources in Newfoundland and Labrador present opportunities to expand the market within the province and to export surplus energy to Atlantic provinces, the eastern seaboard, Europe, and beyond.[236] The province has an abundance of wind (which it notes can be used to power offshore oil and gas developments), as well as opportunities for small-scale solar, and vast ocean access for offshore wind and wave and tidal generation as technology becomes available and economic.[237] The Government of Newfoundland and Labrador also highlighted its willingness to pursue additional opportunities to support the renewable energy priorities of Indigenous governments and organizations in the province.[238] The aim is to maximize benefits for residents with reliable and affordable electricity, economic opportunities in renewable energy, and ensuring a diversified workforce.[239]

The Government of Newfoundland and Labrador has committed to achieving net-zero emissions by 2050, and recognizes that renewable energy can help achieve those goals. There will be a progress report after the first year, halfway through the five-year plan, and at the end of the plan.[240]

VII. HYDROGEN

Hydrogen has been getting a lot of attention in recent years, and has not received this level of attention since the Hindenburg. We have yet to see projects and industry-wide changes come to fruition, but governments are taking action to enable and encourage development

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231 Newfoundland and Labrador, Department of Industry, Energy and Technology, *Maximizing Our Renewable Future: A Plan for Development of the Renewable Energy Industry in Newfoundland and Labrador* (16 December 2021), online: <www.gov.nl.ca/iet/files/Renewable-Energy-Plan-Final.pdf> [*Renewable Energy Plan*].

232 *Ibid* at 6.

233 Terry Roberts, "N.L. Hydro Confirms Muskrat Falls Schedule 'Not Achievable,' with Completion Date Now Uncertain," *CBC News* (14 October 2021), online: <www.cbc.ca/news/canada/newfoundland-labrador/muskrat-schedule-delay-1.6210567>.

234 The Canadian Press Staff, "N.L.'s Muskrat Falls Hydroelectricity Project Delayed Again, this Time until May 31," *The Canadian Press* and *CTV News Atlantic* (26 January 2022), online: <atlantic.ctvnews.ca/n-l-s-muskrat-falls-hydroelectricity-project-delayed-again-this-time-until-may-31-1.5755239>.

235 Juanita Mercer, "Final Commissioning of Muskrat Falls Could Occur by Year's End, " *Saltwire* (17 June 2022), online: <saltwire.com/atlantic-canada/news/final-commissioning-of-muskrat-falls-could-occur-by-years-end-100744975/>.

236 *Renewable Energy Plan*, *supra* note 231 at 8.

237 *Ibid* at 14.

238 *Ibid* at 10.

239 *Ibid* at 12.

240 *Ibid* at 32.

in hydrogen. Alberta released its hydrogen roadmap in November 2021,[241] building on the hydrogen portion of its natural gas vision and strategy that was released in 2020.[242] Air Products Canada Ltd., in conjunction with the federal and Alberta governments, announced a plan to build a new net-zero hydrogen energy complex in Edmonton in June 2021.[243] British Columbia released its hydrogen strategy in July 2021 to help meet its environmental goals and position British Columbia as a leader in the hydrogen economy.[244] Selkirk, Manitoba, home to approximately 11,000 residents, entered into a memorandum of understanding with CHARBONE Hydrogen Corporation to build Manitoba's first green hydrogen production facility in the city.[245]

More information on developments in the hydrogen space can be found in the article by Gavin Fitch, K.C., Michael Barbero, and Kimberly Wasylenchuk.[246]

VIII. MINING

Developments in the mining sector over the past year include: the Government of Alberta's continued recovery from the effects of its decision to rescind and then reinstate its long-standing Coal Policy that limited coal exploration and development in the Eastern Slopes of the Canadian Rockies;[247] a policy statement from the federal government about new thermal coal projects; moves to facilitate the exploration for and development of domestic sources of critical and strategic minerals; and a Helium Action Plan in Saskatchewan.

A. ALBERTA'S *COAL POLICY* REDUX

In 1976, the Government of Alberta adopted the *Coal Development Policy for Alberta*.[248] In 2020, the Government of Alberta rescinded the *Coal Policy* and introduced new leasing rules for coal leases on Crown land without any meaningful consultation.[249]

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241 Government of Alberta, "Hydrogen Roadmap," online: <www.alberta.ca/hydrogen-roadmap.aspx>.

242 Government of Alberta, "Natural Gas Vision and Strategy," online: <www.alberta.ca/natural-gas-vision-and-strategy.aspx>.

243 Air Products, News Release, "Air Products Announces Multi-Billion Dollar Net-Zero Hydrogen Energy Complex in Edmonton, Alberta, Canada" (9 June 2021), online: <www.airproducts.com/news-center/2021/06/0609-air-products-net-zero-hydrogen-energy-complex-in-edmonton-alberta-canada>.

244 Government of British Columbia, *B.C. Hydrogen Strategy: A Sustainable Pathway for B.C.'s Energy Transition* (6 July 2021), online: <www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf>.

245 Dave Baxter, "Selkirk Continues to Build Foundation for Green Economy with Potential Hydrogen Plant," *Winnipeg Sun* (20 January 2022), online: <winnipegsun.com/news/news-news/selkirk-continues-to-build-foundation-for-green-economy-with-potential-hydrogen-plant>.

246 See Gavin Fitch, KC, Michael Barbero & Kimberly Wasylenchuk, "Hydrogen Roadmap: Policy, Regulation, and Prospects for Future Development in Alberta" (2022) 60:2 Alta L Rev 435.

247 For a detailed and informative discussion of Alberta's rescission and reinstatement of its *Coal Policy*, see the eight-part series of posts on *ABlawg* written by Professor Nigel Bankes and Drew Yewchuk. For the final instalment of this series, and access to the others, see: Drew Yewchuk, "Coal Law and Policy Part Eight: The Results of the Coal Consultation and the Return to the *Alberta Land Stewardship Act*" (15 March 2022), online (blog): <ablawg.ca/2022/03/15/coal-law-and-policy-part-eight-the-results-of-the-coal-consultation-and-the-return-to-the-alberta-land-stewardship-act/>.

248 Alberta, Department of Energy and Natural Resources, *A Coal Development Policy for Alberta* (15 June 1976), online: <open.alberta.ca/dataset/cc40f8f5-a3f7-42ce-ad53-7521ef360b99/resource/802d6feb-04ae-4bcc-aac3-3b3be31a0476/download/1114651976coal-development-policy-for-alberta1976-06.pdf> [*Coal Policy*].

249 Government of Alberta, Information Letter 2020-23, "Rescission of *A Coal Development Policy for Alberta* and New Leasing Rules for Crown Coal Leases" (15 May 2020), online: <inform.energy.gov.ab.ca/Documents/Published/IL-2020-23.pdf> [IL 2020-23].

The *Coal Policy* was an early land use planning tool that established four categories of land with differing restrictions on exploration and development. No exploration or commercial development was permitted on Category 1 lands (including national and provincial parks and designated wilderness areas). Increasing levels of development were permitted on the other land categories, but in general, it was difficult to obtain new coal leases except on Category 4 lands.[250]

In rescinding the *Coal Policy*, the Government of Alberta removed all restrictions on issuing coal leases on Category 2 and 3 lands.[251] The government's rationale for rescinding the policy was that "[t]he coal categories are no longer required for Alberta to effectively manage Crown coal leases, or the location of exploration and development activities, because of decades of improved policy, planning, and regulatory processes."[252]

The Government of Alberta's decision to rescind the *Coal Policy* was met with immediate and significant public criticism and on 8 February 2021, the government reinstated the policy.[253] The Minister of Energy admitted that the government had made a mistake that it was now fixing.[254] However, the government did not cancel Crown coal leases that had been issued during the interregnum and that would not have been permitted under the *Coal Policy*.[255] Neither did the government cancel coal exploration programs approved during that time.[256]

On 29 March 2021, the Government of Alberta established the *Coal Policy* Committee (the Committee),[257] which completed two reports, released on 4 March 2022.[258] The Committee made eight recommendations,[259] but its key recommendation was that the *Coal*

250 Government of Alberta, Information Letter 2014-07, "Public Offering of Crown Coal Rights in Alberta" (19 February 2014), online: <inform.energy.gov.ab.ca/Documents/Published/IL-2014-07.pdf> at 1.

251 IL 2020-23, *supra* note 249 at 1.

252 *Ibid*. For a discussion of these policy, planning, and regulatory processes, see: Nigel Bankes, "Coal Law and Policy in Alberta, Part Three: Was the Public Rationale for Rescinding the Coal Policy Ever Convincing?" (15 February 2021), online (blog): <ablawg.ca/2021/02/15/coal-law-and-policy-in-alberta-part-three-was-the-public-rationale-for-rescinding-the-coal-policy-ever-convincing/>.

253 Government of Alberta, Information Letter 2021-07, "Reinstatement of the 1976 Coal Policy" (8 February 2021), online: <inform.energy.gov.ab.ca/Documents/Published/IL-2021-07.pdf>.

254 See Minister Savage's coal policy update: YourAlberta, "Coal Policy Update – February 8, 2021" (8 February 2021) at 00h:00m:35s, online (video): <www.youtube.com/watch?v=fowhdPSbXxs> [Coal Policy Update].

255 The Minister has the authority to cancel a lease if the Minister is of the opinion that further exploration or development within that location is not in the public interest: *Mines and Minerals Act*, RSA 2000, c M-17, s 8(1)(c).

256 Coal Policy Update, *supra* note 254 at 00h:02m:00s (the Minister referred to six approved exploration programs on Category 2 lands, but noted that four of these began while the *Coal Policy* was in place).

257 Government of Alberta, News Release, "Engaging with Albertans on a Modern Coal Policy" (29 March 2021), online: <www.alberta.ca/release.cfm?xID=77832FC8888D0-CED3-59AD-A6561C1C843FD14A>. See here for the Committee's Terms of Reference: Alberta Coal Policy Committee, *Terms of Reference* (29 March 2021), online: <www.alberta.ca/assets/documents/coal-policy-committee-terms-of-reference.pdf>.

258 Alberta, Coal Policy Committee, *Engaging Albertans About Coal* (Coal Policy Committee, 1 December 2021), online: <open.alberta.ca/dataset/78cfffec-e5dc-4474-8617-72b1ca2f4ab2/resource/604fd294-49ba-4942-88b4-5a8fd4d1d191/download/energy-coal-policy-committee-engaging-albertans-2021-12.pdf>; Alberta, Coal Policy Committee, *Final Report: Recommendations for the Management of Coal Resources in Alberta* (Coal Policy Committee, 1 December 2021), online: <open.alberta.ca/dataset/cabeccc3-3937-408a-9eb5-f49af85a7b3f/resource/75d241f9-5567-4a86-91e7-3ed285e42f18/download/energy-coal-policy-committee-final-report-2021-12.pdf> [*Final Report*].

259 *Final Report*, *ibid* at 7–8, 40–44.

Policy should be replaced by a modernized approach to coal exploration and development through regional and subregional plans under the *Alberta Land Stewardship Act*.[260]

The *Coal Policy* remains in place for now. In Ministerial Order 002/2022,[261] the Minister of Energy issued directions to the AER that have the effect of continuing the suspension of applications for Eastern Slopes coal exploration and development, with the exception of advanced projects or active approvals.[262] The preamble to the Ministerial Order states that Eastern Slopes development will remain suspended until "sufficient land use clarity has been provided through a planning activity."[263] This suggests that the Government of Alberta has accepted the Committee's recommendation to replace the *Coal Policy* with a plan made under the *Alberta Land Stewardship Act*, although the timing and process for the development of a new plan remains unclear. Whether the government will accept and act on the other recommendations and "associated observations" made by the Committee is not clear.

B. A NEW FEDERAL POLICY STATEMENT ON THERMAL COAL

On 11 June 2021, the Government of Canada issued a policy statement on thermal coal mining: "[T]he Government of Canada considers that any new thermal coal mining projects, or expansions of existing thermal coal mines in Canada, are likely to cause unacceptable environmental effects. This position will inform federal decision making on thermal coal mining projects."[264] In the related press release, Canada's Minister of the Environment and Climate Change noted:

> New thermal coal mining projects or expansions are not in line with the ambition Canadians want to see on climate, or with Canada's domestic and international climate commitments. Eliminating coal-fired power and replacing it with cleaner sources is an essential part of the transition to a low carbon economy, and as a result, building new thermal coal mines for energy production is not sustainable.[265]

This strongly suggests that new thermal coal mine projects that are subject to federal assessment are unlikely to be approved. Although in general the regulation of natural resources is a matter of provincial jurisdiction, the *Impact Assessment Act*[266] gives the IAAC the authority to carry out an impact assessment for "designated projects,"[267] which for coal

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260 SA 2009, c A-26.8.

261 Alberta, Department of Energy, Ministerial Order 002/2022 (2022), (*Responsible Energy Development Act)*, online: <www.qp.alberta.ca/Documents/MinOrders/2022/Energy/2022_002_Energy.pdf> [MO 002/2022].

262 Under MO 002/2022, *ibid*, an advanced coal project is a project for which the proponent has submitted a project summary to the AER for the purposes of determining whether an environmental impact assessment is required.

263 MO 002/2022, *ibid* at 2.

264 Government of Canada, Policy Statement, "Statement by the Government of Canada on Thermal Coal Mining," online: <www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/electricity-generation/statement-government-canada-thermal-coal-mining.html> [Policy Statement].

265 Environment and Climate Change Canada, News Release, "Government of Canada Releases Policy Statement on Future Thermal Coal Mining Projects and Project Expansions" (11 June 2021), online: <www. canada.ca/en/environment-climate-change/news/2021/06/government-of-canada-releases-policy-statement-on-future-thermal-coal-mining-projects-and-project-expansions.html>.

266 *IAA*, *supra* note 75 (note that the Alberta Court of Appeal has ruled that the *IAA* is an unconstitutional infringement by Parliament of provincial powers: *Reference re Impact Assessment Act*, 2022 ABCA 165).

267 *Physical Activities Regulations*, SOR/2019-285, s 2, Schedule.

projects is determined using a production and size threshold.[268] The federal Minister of the Environment and Climate Change also has the discretion to designate a new coal mine or an expansion below these thresholds,[269] and the Policy Statement makes the point that the new policy will inform the Minister's exercise of discretionary authority to designate such sub-threshold projects.[270] The new federal policy applies only to thermal coal. It does not apply to metallurgical coal. Thermal coal is coal that is used to generate electricity. Metallurgical coal is a source of coke, which is an essential component of steelmaking.[271] Since the phasing out of coal-fired power generation in Canada is well underway, it is unlikely that the federal government's new policy will have much impact on the production of thermal coal for domestic consumption, but it may affect projects intended to serve export markets. However, Canada's coal exports are primarily metallurgical, with metallurgical coal accounting for 95 percent of exports in 2019.[272]

C. DOMESTIC PRODUCTION OF STRATEGIC AND CRITICAL MINERALS

When they were first discovered, so-called rare earth elements and their interesting properties were primarily of academic scientific interest. However, they have become critical components of electronics and battery manufacturing and demand for them continues to increase. Global production of rare earth elements is dominated by China.[273]

Governments have increasingly become concerned about the effects of supply shortages and the vulnerability associated with dependence on a small number of suppliers. The Government of Alberta recently developed a strategy to "re-energize Alberta's minerals sector" and encourage development of critical and strategic minerals such as lithium, uranium, vanadium, and rare earth elements.[274] This strategy is intended to work together with the federal *Canadian Minerals and Metals Plan*,[275] as well as the *Canada-U.S. Joint Action Plan on Critical Minerals Collaboration*.[276]

The goal of Alberta's strategy is to become a "preferred producer and supplier of minerals and mineral products and actively [contribute] to the global energy transformation."[277] The

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268 *Ibid*, ss 18(a), 19(a).

269 *IAA*, *supra* note 75, s 9.

270 Policy Statement, *supra* note 264.

271 See e.g. University of Alberta, Department of Earth and Atmospheric Sciences, "Metallurgical Coal," online: <www.ualberta.ca/earth-sciences/facilities/collections-and-museums/minerals-of-alberta/metallurgical-coal.html>; Natural Resources Canada, "Coal Facts," online: <www.nrcan.gc.ca/our-natural-resources/minerals-mining/minerals-metals-facts/coal-facts/20071> [Coal Facts].

272 Coal Facts, *ibid*.

273 See e.g. Government of Canada, "Rare earth elements facts," online: <www.nrcan.gc.ca/our-natural-resources/minerals-mining/minerals-metals-facts/rare-earth-elements-facts/20522>.

274 Government of Alberta, *Renewing Alberta's Mineral Future: A Strategy to Re-Energize Alberta's Minerals Sector* (Edmonton: Ministry of Energy, November 2021), online: <open.alberta.ca/dataset/9d147a23-cb06-413d-a60e-ad2d7fe4e682/resource/73ebd14b-a687-4772-9982-48843b677c28/download/energy-renewing-albertas-mineral-future-report-2021.pdf> [*Renewing Alberta's Mineral Future*].

275 Natural Resources Canada, *The Canadian Minerals and Metals Plan*, Catalogue No M4-175/2019E-PDF (March 2019), online: <www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/CMMP/CMMP_The_Plan-EN.pdf>.

276 Natural Resources Canada, News Release, "Canada and U.S. Finalize Joint Action Plan on Critical Minerals Collaboration" (9 January 2020), online: <www.canada.ca/en/natural-resources-canada/news/2020/01/canada-and-us-finalize-joint-action-plan-on-critical-minerals-collaboration.html>.

277 *Renewing Alberta's Mineral Future*, *supra* note 274 at 12.

Alberta government's two-year action plan includes increasing public geoscience, enhancing the fiscal and regulatory environment, promoting responsible development, advancing opportunities for Indigenous peoples, developing a skilled workforce, and promoting innovation and industrial development.[278]

The enhancement of the fiscal and regulatory environment includes modernizing the metallic and industrial mineral tenure, developing a regulatory roadmap to provide clear guidance to industry, and updating the industrial mineral regulatory regime.[279] As part of this goal, the Legislature passed (but has not yet proclaimed), the *Mineral Resource Development Act*.[280]

The *MRDA* applies to naturally occurring mineral resources,[281] as well as related production and processing facilities throughout their life cycles. The *MRDA* gives the AER the authority to deal with the regulation of Alberta's mineral resources, which was formerly administered by several departments and regulators. The powers the *MRDA* gives the AER closely resemble those that it uses to regulate the oil and gas sector.

Interestingly, the *MRDA* gives the AER the authority to designate wells that were previously licenced under the *Oil and Gas Conservation Act*[282] and the *Geothermal Resource Development Act*[283] as mineral wells, paving the way for existing wells to be reused for mineral purposes.

The *MRDA* is the Government of Alberta's first step in implementing its new mineral strategy. While the *MRDA* promises a streamlined "one-window" regulatory process administered by the AER, the regulatory framework is still incomplete. At this point, it is not clear what rules and directives the AER will make once the *MRDA* is proclaimed, and many of the issues that the AER will have to deal with will be new to it. Furthermore, traditional methods of extracting and processing many of the strategic and critical materials that the Alberta government's strategy is aimed at have significant environmental impacts,[284] and the rules that will be necessary to achieve the government's objective of responsible development have yet to be made.

In its 2022 budget, the Government of Canada introduced financial measures to incentivize domestic production of strategic minerals. These include up to $3.8 billion between now and 2030 to implement the Critical Minerals Strategy and a new 30 percent Critical Mineral Exploration Tax Credit.[285]

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278 *Ibid* at 21–22.
279 *Ibid* at 21.
280 SA 2021, c M-16.8 [*MRDA*].
281 The *MRDA* does not apply to petroleum, oil, asphalt, bituminous sands, oil sands, natural gas, coal, ammonite shell, sand, gravel, clay, peat, or marl: *ibid*, s 1(1)(p).
282 RSA 2000, c O-6.
283 SA 2020, c G-5.5 [*GRDA*].
284 See e.g. Xiangbo Yin et al, "The Potential Environmental Risks Associated with the Development of Rare Earth Element Production in Canada" (2021) 29:3 Environmental Rev 354, online: *Canadian Science Publishing* <cdnsciencepub.com/doi/10.1139/er-2020-0115>; Jaya Nayar, "Not So 'Green' Technology: The Complicated Legacy of Rare Earth Mining," *Harvard International Review* (12 August 2021), online: <hir.harvard.edu/not-so-green-technology-the-complicated-legacy-of-rare-earth-mining/>.
285 Canada, Department of Finance, *2022 Budget: A Plan to Grow Our Economy and Make Life More Affordable*, Catalogue No 1719-7740 (Ottawa: Department of Finance, 2022) at 57–86 [*Federal Budget*].

D. SASKATCHEWAN HELIUM ACTION PLAN

The Government of Saskatchewan launched its Helium Action Plan on 15 November 2021, outlining how it expects to become a world leader in helium production and export.[286] Saskatchewan's unique geology yields high concentrations with a low greenhouse gas emissions profile, up to 99 percent less carbon intensive than other jurisdictions.

Saskatchewan already has a helium regulatory framework in place, and an existing industry. In April 2021, Canada's largest helium purification facility opened in Saskatchewan.[287] The facility is expected to produce more than 50 million cubic feet of purified helium per year. Helium is used in medical research, semiconductor manufacturing, space exploration, fiber optics, and advancements in nuclear power.

Helium is one of the only elements that is completely non-renewable. It is also lightweight and does not readily combine with other elements, so once brought to the surface, it can easily escape. Helium production comes predominantly from a handful of countries. If any of those countries experience issues, it can lead to shortages and price volatility. This in turn can lead researchers to question whether to delay or abandon important research.[288]

There are two principal ways to produce helium: (1) capture it as a byproduct of natural gas; or (2) extract it from dedicated helium wells. Saskatchewan is one of the few jurisdictions in the world that can support helium production as a standalone sector because of the province's geology and high helium concentrations.

The province also expanded its Petroleum Innovation Incentive to apply to helium.[289] The program offers tax credits for qualified projects across oil, gas, and helium sectors.

IX. GEOTHERMAL

Geothermal energy is heat originating deep below the earth's surface that can be used for heating or generating clean electricity. Geothermal systems involve injecting cooler water into the formation, and bringing hot water to the surface, either in an open or closed loop system.[290] Canada does not currently have any geothermal power generation, although a proposed Saskatchewan project aims to be the first geothermal power generation facility in the country.[291]

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286 Government of Saskatchewan, News Release, "Government of Saskatchewan Launches Helium Action Plan" (15 November 2021), online: <www.saskatchewan.ca/government/news-and-media/2021/november/15/government-of-saskatchewan-launches-helium-action-plan>.

287 Government of Saskatchewan, News Release, "Canada's Largest Helium Purification Facility Opens In Saskatchewan" (27 April 2021), online: <www.saskatchewan.ca/government/news-and-media/2021/april/27/canadas-largest-helium-purification-facility-opens-in-saskatchewan>.

288 Geoff Brumfiel, "The World Is Constantly Running Out of Helium. Here's Why It Matters," *NPR* (8 November 2019), online: <www.npr.org/2019/11/01/775554343/the-world-is-constantly-running-out-of-helium-heres-why-it-matters>.

289 Government of Saskatchewan, "Oil and Gas Processing Investment Incentive (OGPII)," online: <www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-incentives-crown-royalties-and-taxes/oil-and-gas-processing-investment-incentive> [OGPII].

290 Alberta Energy Regulator, "Geothermal Resource Development," online: <www.aer.ca/providing-information/by-topic/emerging-resources/geothermal-resource-development>.

291 DEEP Earth Energy Production Corp, "About DEEP," online: <deepcorp.ca/about-deep/>.

On 8 December 2021, the Government of Alberta proclaimed the *Geothermal Resource Development Act* establishing the AER as the primary regulator for deep geothermal energy developments in Alberta.[292] The Government of Alberta is accepting tenure applications for geothermal leases, and received eight applications in January 2022 and seven in February 2022.[293]

The AER is still working to finalize the details of the regulatory framework, including the application process and technical requirements for development of geothermal resources. It plans to publish the final requirements in spring 2022.[294] The AER is not able to accept geothermal applications until the regulatory scheme is finalized.

More information on geothermal energy can be found in the article by Professor David R. Percy, K.C.[295]

X. GREENHOUSE GAS EMISSION REDUCTION

The reduction of greenhouse gas emissions is a continuing hot topic and focus for all levels of government. The past year has seen progress on carbon capture projects, changes to how Saskatchewan and Ontario treat large industrial emitters, the beginnings of a clean energy credit regime for reductions in emissions in Ontario, and the rates for electric vehicles.

A. CARBON CAPTURE, UTILIZATION, AND STORAGE (CCUS)

The most recent development on carbon capture, utilization, and storage (CCUS) is the federal government's CCUS Tax Credit that was announced in its 2022 budget on 7 April 2022.[296] The CCUS Tax Credit is a refundable tax credit for businesses that incur eligible CCUS expenses, starting in 2022, and will be available to CCUS projects to the extent they permanently store CO_2 through an "eligible use," which includes dedicated geological storage and storage of CO_2 in concrete, but not enhanced oil recovery schemes.[297] The exclusion of these schemes has been criticized by industry as putting Canada at a competitive disadvantage compared to the US, which allows its CCUS credit to be used for such schemes.[298]

The 2022 Federal Budget states that the tax credit rate from 2022 to 2030 will be set at 60 percent for investment in equipment to capture CO_2 in direct air capture projects, 50 percent for investment in equipment to capture CO_2 for other types of CCUS projects, and 37.5

292 *GRDA*, *supra* note 283; Government of Alberta, "Geothermal Resource Development," online: <www.alberta.ca/geothermal-resource-development.aspx>.
293 Government of Alberta, "Geothermal Resource Development," *ibid*.
294 Alberta Energy Regulator, *Bulletin 2021-46: Geothermal Resource Development Act (GRDA) Proclamation* (Calgary: Alberta Energy Regulator, 13 December 2021), online: <static.aer.ca/prd/documents/bulletins/Bulletin-2021-46.pdf>.
295 David R Percy, KC, "Ownership Issues in the Production of Geothermal Energy" (2022) 60:2 Alta L Rev 523.
296 *Federal Budget*, *supra* note 285 at 89–110.
297 *Ibid* at 97.
298 Meghan Potkins, "Trudeau Proposes Tax Credit to Cover 50% of Carbon Capture Technology Cost," *Financial Post* (7 April 2022), online: <financialpost.com/commodities/energy/oil-gas/trudeau-proposes-tax-credit-to-cover-50-of-carbon-capture-technology-cost>.

percent for investment in equipment for transportation, storage, and use. To incentivize CCUS projects to be built quickly, these percentages will be reduced by 50 percent from 2031 to 2040.[299]

There has also been notable CCUS development at the provincial level.

Alberta is the most advanced in CCUS as a result of its 2010 amendment to the *Mines and Minerals Act*[300] that, among other things, declared the ownership of pore space in Alberta to be vested in the Crown, and added Part 9 to the *Act* which provided for agreements with the Crown to drill evaluation wells and inject captured CO_2 into a subsurface reservoir for sequestration.[301] In 2011, the Government of Alberta also decided to subsidize certain CCUS projects, two of which (the Quest CCUS project and the Alberta Carbon Trunk Line) were built, with the Government of Alberta committing $1.24 billion through 2025 for these two projects which it estimates will reduce CO_2 emissions by 2.76 million tonnes per year.[302]

More recently, the Government of Alberta is preparing to issue carbon sequestration rights through a competitive process, enabling the development of carbon storage hubs. In the fall of 2021, the province requested expressions of interest from companies interested in developing and operating a carbon sequestration hub in Alberta. The province initially requested proposals that would primarily enable sequestration of carbon emissions from Alberta's industrial heartland region near Edmonton. That process has closed, and the province has announced that it has selected six proposals to begin exploring how to safely develop storage hubs in the region.[303]

The province plans to work with the proponents of these proposals to evaluate the suitability of each location for safely storing carbon and to work with the Government of Alberta on an agreement to provide the right to inject carbon dioxide. The province is also now welcoming hub proposals that will enable the sequestration of carbon dioxide emissions in all other regions of Alberta. These proposals will be accepted between 25 April and 2 May 2022.[304]

There have also been CCUS developments in Saskatchewan and Ontario. In November 2021, the Government of Saskatchewan announced that pipelines transporting carbon dioxide, whether for CCUS or enhanced oil recovery, are eligible for the provincial Oil Infrastructure Investment Program which provides transferrable oil and gas royalty production credits at a rate of 20 percent of eligible project costs.[305]

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299 *Federal Budget*, *supra* note 285 at 89–110.
300 *Supra* note 255.
301 *Ibid*, ss 15.1, 115–16.
302 Government of Alberta, "Carbon Capture, Utilization and Storage – Overview," online: <www.alberta.ca/carbon-capture-utilization-and-storage-overview.aspx>.
303 Government of Alberta, "Carbon Sequestration Tenure Management," online: <www.alberta.ca/carbon-sequestration-tenure-management.aspx>.
304 *Ibid*.
305 Government of Saskatchewan, News Release, "Oil Infrastructure Program Expanded to Support Carbon Capture" (4 November 2021), online: <www.saskatchewan.ca/government/news-and-media/2021/november/04/oil-infrastructure-program-expanded-to-support-carbon-capture>; OGPII, *supra* note 289.

In January 2022, the Government of Ontario issued a discussion paper titled *Geological Carbon Storage in Ontario*.[306] The province's resource-extraction laws currently prohibit the injection of carbon dioxide underground. The discussion paper states that the government is considering narrowing the prohibition to only prohibit injection of carbon dioxide with a project to enhance the recovery of oil and gas. The Government of Ontario ran a public consultation process inviting comments on the discussion paper from 11 January 2022 to 14 March 2022.[307]

B. CARBON PRICING SYSTEM FOR INDUSTRIAL FACILITIES

In June 2018, the Government of Canada passed the *Greenhouse Gas Pollution Pricing Act*.[308] Part 2 of this *Act* implemented an output-based pricing system (OBPS) for industrial facilities which requires "covered facilities," as defined in the *Act* and its regulations, to compensate for greenhouse gas emissions that exceed an annual facility emissions limit. The OBPS is applicable to provinces and territories unless the federal government determines that the provincial or territorial system meets its stringency requirements for the emission sources they cover. Up until this year, only Yukon, Nunavut, Saskatchewan (for some sectors only), Ontario, and Prince Edward Island were subject to the federal OBPS.[309]

In the past year, both Saskatchewan and Ontario have taken steps to allow (or to allow more, in the case of Saskatchewan) industrial facilities in their province to transition from the federal government's OBPS to their own system.

Saskatchewan's provincial OBPS was first introduced in January 2019 in *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*.[310] Until this year, these regulations only covered some of Saskatchewan's industrial facilities, with the result that the federal OBPS applied to industrial facilities not covered by the Saskatchewan system. Effective 1 January 2022, industrial facilities in five additional sectors will be covered by Saskatchewan's OBPS. These sectors are: chemical manufacturing; wood product manufacturing; mineral product manufacturing; agricultural and industrial equipment manufacturing; and food and beverage processing.

Under the provincial OBPS, the threshold for participation has been reduced from 10,000 tonnes carbon dioxide equivalent (CO_2e) to 0 tonnes CO_2e. Saskatchewan also plans to submit a proposal to the federal government to bring the final two remaining sectors of

306 Ontario, Ministry of Northern Development, Mines, Natural Resources and Forestry, *Discussion Paper: Geologic Carbon Storage in Ontario* (Ottawa: Ministry of Northern Development, Mines, Natural Resources and Forestry, 11 January 2022), online: <prod-environmental-registry.s3.amazonaws.com/2022-01/Geologic%20Carbon%20Storage%20Discussion%20Paper%20-%20FinalENG%20-%202022-01-04_0.pdf>.

307 Ontario, Ministry of Northern Development, Mines, Natural Resources and Forestry, *Discussion Paper: Geologic Carbon Storage in Ontario*, Policy Notice 019-4770 (Toronto: Ministry of Northern Development, Mines, Natural Resources and Forestry, 11 January 2022), online: <ero.ontario.ca/notice/019-4770>.

308 SC 2018, c 12, s 186.

309 Government of Canada, "Carbon Pollution Pricing Systems Across Canada," online: <www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html>.

310 RRS c M-2.01, Reg 3.

electricity generation and natural gas transmission into the Saskatchewan system.[311] The Government of Saskatchewan expects that 30 additional facilities will register under the expanded provincial OBPS, bringing the total savings to Saskatchewan's industries to $2.3 billion by 2030, compared to the federal industrial pricing system that would otherwise be imposed by the federal government.[312]

In September 2021, the federal government determined that Ontario's emissions performance standards program (EPS) met its stringency requirements and will apply for Ontario industrial facilities beginning on 1 January 2022. Like the federal OBPS and other provincial OBPSs, the EPS establishes emission performance standards for certain large industrial facilities in Ontario that will become stricter every year, requiring emitters to reduce their emissions or pay for exceeding the limits. The program was created under the *Greenhouse Gas Emissions Performance Standards* regulation,[313] which was enacted in 2019. Under the EPS, facilities that reported 50,000 tonnes or more of CO_2e from 2014 onward must register, and facilities that reported between 10,000 and 50,000 tonnes may opt-in to the program.

To support a smooth transition from the federal OBPS to the EPS, the Government of Ontario has made regulatory amendments to the *GGEPSR* and other enactments.[314] Such amendments include providing a grace period for compliance obligations for most new facilities, aligning the EPS with federal OBPS standards for the electricity sector (i.e., 370 tonnes CO_2e/GWh), and clarifying the application of the cogeneration standard to Ontario facilities.[315] Other amendments are intended to ensure that facilities are not charged twice for the same emissions under the EPS program and either the federal OBPS or the federal fuel charge, there is no gap in pricing for emissions because of the transition from the federal OBPS to the EPS program, and covered facilities will remain eligible for their exemption from the federal fuel charge.[316]

C. CLEAN ENERGY CREDITS IN ONTARIO

Ontario is also planning on implementing a system for trading renewable energy attributes within the Ontario electricity market. The Government of Ontario has directed the IESO to research and report back on the design of a provincial clean energy credits registry that would give businesses more choice in how they achieve their corporate sustainability goals. The IESO will deliver its report by 4 July 2022. The government will consider the report, as

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311 Government of Saskatchewan, News Release, "Saskatchewan Expands OBPS to Protect Additional Sectors from the Federally Imposed Carbon Tax" (19 January 2022), online: <www.saskatchewan.ca/government/news-and-media/2022/january/19/saskatchewan-expands-obps-to-protect-additional-sectors-from-the-federally-imposed-carbon-tax>.

312 *Ibid*.

313 O Reg 241/19 [*GGEPSR*].

314 See amendments to the following regulations and incorporated documents: *ibid* (and the incorporated GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit); *Greenhouse Gas Emissions: Quantification, Reporting and Verification*, O Reg 390/18 (and the incorporated Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions).

315 Ontario, Ministry of the Environment, Conservation and Parks, *Amendments to Support Transition and Implementation of Ontario's Emissions Performance Standards Program*, Policy Notice 019-3719 (Toronto: Ministry of the Environment, Conservation and Parks, 22 October 2021), online: <ero.ontario.ca/notice/019-3719>.

316 *Ibid*.

well as stakeholder input, with the intention of having the registry available by January 2023.[317]

D. NOVA SCOTIA'S *ENVIRONMENTAL GOALS AND CLIMATE CHANGE REDUCTION ACT*

Nova Scotia is also taking steps to reduce greenhouse emissions. In November 2021, the Government of Nova Scotia passed the *Environmental Goals and Climate Change Reduction Act*.[318] This *Act* codifies 28 new goals towards the environment and climate change reduction, including the strongest 2030 greenhouse gas emission reduction target in Canada, which requires the province to be 53 percent below 2005 levels of greenhouse gas emissions by 2030 and be net-zero by 2050 (by balancing greenhouse gas emissions with greenhouse gas removals and other offsetting measures).[319]

The *Act* also includes a commitment to phasing out coal-fired electricity by 2030, a requirement to implement a zero-emission vehicle (ZEV) mandate to ensure 30 percent of vehicles sold by 2030 are ZEVs, and to have 80 percent of the electricity in the province supplied by renewable energy by 2030.[320]

E. ELECTRIC VEHICLES

Electric vehicles (EVs) continue to be a focus of the federal, British Columbia, and Quebec governments. In the 2022 Federal Budget announced on 7 April 2022, the government committed to extending the incentive (up to $5,000) for light-duty ZEVs until March 2025. It also broadened the program to support the purchase of more vehicle models, including more vans, trucks, and SUVs.[321] The 2022 Federal Budget expands the availability of zero-emission electric vehicles and charging stations, and promises to launch a new purchase incentive program for medium and heavy-duty ZEVs.[322]

At the provincial level, EV development continues to be most prominent in British Columbia and Quebec, likely due to incentives in those provinces and ZEV mandates that require carmakers to sell a minimum percentage of EVs.

This year, there have been notable developments in both provinces on the rates for EV fast charging stations.

In 2018, the British Columbia Utilities Commission (BCUC) launched an inquiry into the general EV charging services market in British Columbia and the EV charging services market for public utilities involvement. Following this inquiry, the Government of British Columbia exempted from regulation those service providers who were not public utilities (such as Tesla, ChargePoint, and 7-11). For public utilities, the government amended the

317 Government of Ontario, News Release, "New Ontario Clean Energy Registry Will Make Province Even More Attractive for Investment" (26 January 2022), online: <news.ontario.ca/en/release/1001486/new-ontario-clean-energy-registry-will-make-province-even-more-attractive-for-investment>.
318 SNS 2021, c 20.
319 *Ibid*, s 6.
320 *Ibid*, s 7.
321 *Federal Budget*, *supra* note 285 at 91–92.
322 *Ibid*.

Greenhouse Gas Reduction (Clean Energy) Regulation to allow for investments in EV charging infrastructure as prescribed undertakings[323] and requiring the BCUC, under the *Clean Energy Act*,[324] to set rates to allow public utilities to recover their cost of service for such undertakings.

FortisBC Inc. (FortisBC) and BC Hydro and Power Authority (BC Hydro) are the only public utilities to date to apply for approval for rate design and rates to provide EV direct current fast charging stations (DCFC) in British Columbia. Two notable decisions have occurred in the past year regarding EV fast charging rates for these two public utilities.[325] In both decisions, the BCUC approved time-based rates (charging rates per minute) as opposed to energy-based rates (charging rates per kWh), but left the door open for approval of energy-based rates in the future in the event Measurement Canada approves an energy-based meter.

On 24 November 2021, the BCUC approved FortisBC's rates on a permanent basis (calculated as 10-year levelized rates) for EV charging service at FortisBC owned DCFCs at $0.26/minute for 50 kW stations and $0.54/minute for 100 kW stations.[326] The BCUC noted that the rates approved were heavily reliant on current assumptions about demand elasticity and station utilization and therefore, directed FortisBC to file a detailed assessment of its rates on the earlier of either 31 December 2022 or six months after Measurement Canada's approval of DCFC energy-based metering.[327]

On 26 January 2022, the BCUC rejected BC Hydro's proposed permanent EV charging rates.[328] The BCUC found that the proposed rates were not just and reasonable because they did not recover BC Hydro's cost of service. Rather, the rates were designed to only recover electricity costs and not other incremental costs such as operating and maintenance costs, and capital costs.[329] As a result of this under-recovery, the BCUC held that the rate would be subsidized by other BC Hydro services, which creates an unlevel playing field for unregulated EV charging service providers, and that this could have a detrimental impact on EV adoption.[330] The BCUC directed BC Hydro to file a new application that establishes separate classes of services for its EV fast charging service and that addresses the issues identified by the BCUC.

In Quebec, the government sets the rates, by regulation, for public fast charging service for EVs pursuant to its *Regulation Respecting the Rates for Using the Public Fast-Charging Service for Electric Vehicles*.[331] As of 1 January 2022, these rates were amended from a flat

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323 BC Reg 102/2012, s 5(2).
324 SBC 2010, c 22, s 18(2).
325 *FortisBC Inc: Application for Approval of Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service* (24 November 2021), Decision and Order G-341-21, online: BCUC <docs.bcuc.com/Documents/Other/2021/DOC_64973_G-341-21-FBC-EV-DCFC-Rates-and-Rate-Design-Decision-and-Order.pdf> [*FortisBC Inc Application*]; *British Columbia Hydro and Power Authority: Public Electric Vehicle Fast Charging Service Rates Application* (26 January 2022), Decision and Order G-18-22, online: BCUC <docs.bcuc.com/Documents/Other/2022/DOC_65431_G-18-22-BCH-EV-Fast-Charging-Rates-Decision.pdf> [*BC Hydro Application*].
326 *FortisBC Inc Application*, *ibid*.
327 *Ibid* at ii.
328 *BC Hydro Application*, *supra* note 325.
329 *Ibid* at i.
330 *Ibid* at 36.
331 CQLR c H-5, r 1.

rate for 50 kW fast charging stations to a tiered pricing system for different levels of charging power (24 kW, 50 kW, and 100+ kW).[332]

XI. CONCLUSION

Two broad themes permeate the regulatory and legislative developments over the past year. The first is the increasing importance and urgency of steps to address climate change. Regulators will continue to face new and evolving issues, often without the benefit of explicit legislative guidance. The appetite of regulators to venture into these uncharted waters without that guidance differs by issue and sometimes by jurisdiction.

The second theme is the continuing evolution of the law related to engagement, consultation, and assessing potential impacts to First Nations. For the first time, a Canadian Court has found a breach of Indigenous treaty rights based on cumulative impacts.

Another area to keep an eye on is the development of a domestic critical mineral industry. It remains to be seen whether a domestic industry can compete with foreign sources that often have lower costs because of different labour and environmental standards.

We expect many of the same trends to continue in the coming years. With the federal government's commitment to increasing the carbon tax, provinces setting ambitious goals for emission reductions, and municipalities declaring climate emergencies, we expect decarbonization efforts to continue to drive developments at the government policy and corporate levels.

Nevertheless, we expect that oil and gas will continue to be a key form of energy production for the foreseeable future. High energy prices have highlighted the importance of energy to consumers, and if they persist, may hasten the adoption of alternative energy sources by making them more competitive and by spurring research and development investments.

There will be lots to watch in the coming year, including how other Canadian jurisdictions will deal with cumulative impacts of Aboriginal and treaty rights, the implementation of Alberta's legislation to modernize its electricity system, and the recent Alberta Court of Appeal's opinion finding that the *IAA* is unconstitutional (which is being appealed to the Supreme Court of Canada).[333]

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332 Tarifs d'utilisation du service public de recharge rapide pour véhicules électriques (Minister of Energy and Natural Resources), (2021) GOQ 1, 765, online: *Government of Quebec* <www2.publicationsduquebec.gouv.qc.ca/dynamicSearch/telecharge.php?type=4&file=2152.PDF>.

333 *Reference re Impact Assessment Act*, 2022 ABCA 165, appeal as of right to SCC, 40195 (8 June 2022).