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Canadian Power

Key Developments in 2017
Trends to Watch for in 2018

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The Power Group at McCarthy Tétrault LLP is pleased to present *Canadian Power* – *Key Developments in 2017 – Trends to Watch for in 2018*. It is our third annual Canadian power industry retrospective. The idea behind this publication is to provide an overview, at both the regional and national levels, of the most significant developments in the Canadian power sector in 2017, including in the areas of environmental and aboriginal law, mergers & acquisitions and energy litigation, and to highlight key trends to watch for in 2018.

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Special thanks to our publication authors: Dominique Amyot-Bilodeau, Stephanie Axmann, Scott Bergen, Louis-Nicolas Boulanger, Niki Gill, Daniel Goudge, Bryn Gray, Kimberly Howard, Cameron Hughes, Ainslie Hurd, James Klein, Mathieu LeBlanc, Selina Lee-Andersen, Samuel Lepage, Kim Martyn, Zachary Masoud, Sven Milelli, Seán C. O'Neill, Julie Parla, Brianne Paulin, Robin Sirett, Martin Thiboutot, Morgan Troke, Matthieu Rheault, Sam Rogers, Joanna Rosengarten and George Vegh.

REGIONAL PERSPECTIVES

British Columbia

Morgan Troke

Sven Milelli

Selina Lee-Andersen

Robin Sirett

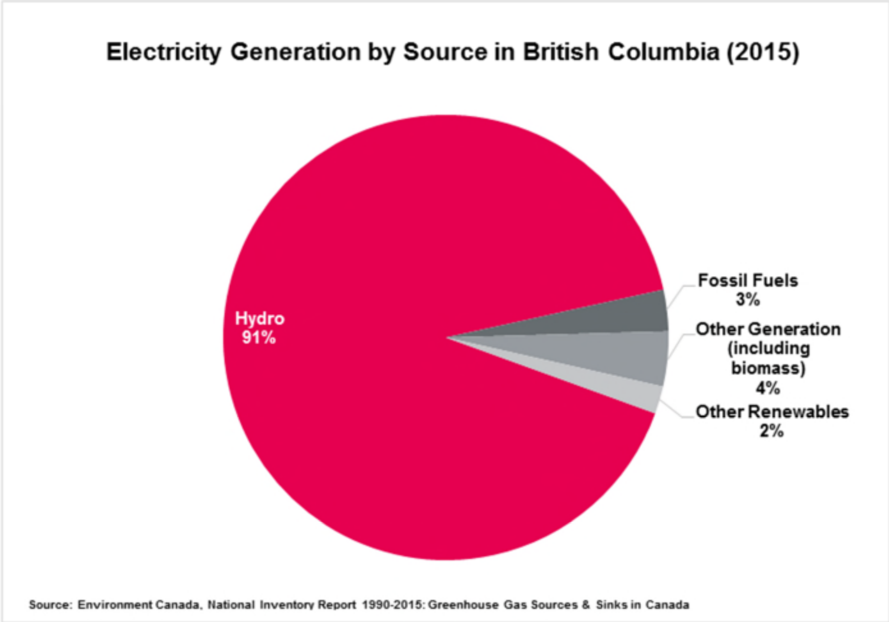
Stephanie Axmann

Ainslie Hurd

Introduction

With no new significant power procurement opportunities on the horizon, BC's power sector began adjusting to a newly-elected NDP Government while remaining focused on a number of industry developments including:

- the status of BC Hydro's 1,100MW Site C Clean Energy Project lcated in the Peace Region (Site C Project), the continued construction of which was confirmed by the Province as the year drew to a close;
- continued anticipation regarding development of LNG projects in the Province and the opportunities associated with related loads;
- suspension of BC Hydro's Standing Offer Program and Micro-Standing Offer Program;
- the decision regarding BC Hydro's rate design application; and
- the Provincial Government's planned comprehensive review of BC Hydro, the preparation of BC Hydro's 2018 Integrated Resource Plan, and the development of a Provincial energy roadmap for the future.



PRESSING ON – SITE C PROJECT TO PROCEED TOWARD COMPLETION

On December 11, 2017, the Province announced its decision to complete construction of the Site C Project, concluding that cancelling the project mid-construction would have imposed a $4 billion burden on provincial taxpayers, comprising $2.1 billion already spent and an estimated $1.8 billion in termination and site remediation costs. The Province also confirmed that the capital cost estimate for Site C has been updated to $10.7 billion from BC Hydro's original estimate of $7.9 billion.

In moving forward with the project, the Province also announced a Site C "turnaround plan" to contain project costs and secure additional project-related benefits, including:

- a new "Project Assurance Board" to provide oversight over future contract procurement and management, project deliverables, environmental matters and quality assurance;
- a new community benefits program to ensure project benefits to local communities and to increase the number of apprentices and First Nations workers working on the project; and
- a new BC Food Security Fund to be funded by Site C revenues and dedicated to supporting farming and agricultural innovation and productivity in the Province.

In addition, the Province and BC Hydro will consider the development of a new procurement stream for smaller-scale renewable electricity projects of which First Nations are proponents or partners, expanding or complementing BC Hydro's existing Standing Offer Program following its review (discussed further below).

Construction of Site C, which received provincial and federal environmental approvals in October 2014, began in summer 2015. Both prior to and since the start of construction, the project has faced significant opposition from various stakeholders, including landowners and First Nations in the Peace Region, several of whom launched court challenges against Site C. The Peace Valley Landowner Association's proceedings against the Government concluded in September 2016 when the BC Court of Appeal affirmed the lower court's ruling that the decision by the Minister of the Environment was reasonable. In early 2017, the federal and provincial appellate courts dismissed challenges of Site C's federal and provincial environmental assessment approvals, which had been brought by the West Moberly and Prophet River First Nations.

In August 2017, the newly-elected government led by Premier John Horgan requested that the British Columbia Utilities Commission (BCUC) review the impact on BC Hydro ratepayers associated with continuing, suspending or terminating the Site C Project.

Reporting in November 2017, the BCUC's found that:

- the Site C Project is unlikely to be completed on time or on budget, and the BC Hydro load forecast underlying the project's construction is excessively optimistic;
- suspending and restarting the Site C Project in 2024 is by far the least attractive option, adding an estimated $3.6 billion to final costs and creating significant risk due to the expiration of applicable approvals and permits;
- project termination and remediation costs would be approximately $1.8 billion, in addition to the costs of finding alternative energy sources to meet demand; and
- increasingly viable alternative energy sources such as wind, geothermal and industrial curtailment could provide similar benefits to ratepayers as the Site C Project, with an equal or lower unit energy cost.

Certain findings were subsequently challenged by the Province, BC Hydro and others, but the regulator did not change its main conclusions. Following the publication of the BCUC report, the Province consulted with a number of additional industry participants before coming to its decision to proceed with the completion of the project.

Site C will be the third dam and hydroelectric generating station on the Peace River in northeast BC. Following its expected in-service date of 2024 it will produce about 5,100 gigawatt hours of electricity each year – enough to power the equivalent of about 450,000 homes per year. In accordance with the province's *Clean Energy Act*, Site C will be the last major hydroelectric project to be undertaken by BC Hydro.

LNG UPDATE

In light of the change in Provincial Government and continuing challenges faced by the global energy market, LNG projects in BC continued to face uncertainty in 2017. While a provincial regulatory framework has been established for the development of the LNG industry in BC, only Woodfibre LNG Limited has announced that it will move forward with its proposed facility in Squamish. As of December 2017, there were 17 LNG export proposals in BC at various stages of development (four of which have received both provincial and federal environmental assessment approvals: Woodfibre LNG, Kitimat LNG, LNG Canada and Pacific NorthWest LNG). In July 2017, Pacific NorthWest LNG announced that it would not be proceeding with the development of its LNG project in the District of Port Edward. A final investment decision on LNG Canada's proposed LNG facility in Kitimat (a joint venture by Shell, PetroChina, Mitsubishi Corporation and Kogas) may be announced in 2018. The LNG Canada project is slated to draw approximately 2,000 GWh/year of electricity from BC Hydro's grid to power ancillary (i.e. non-liquefaction) activities.

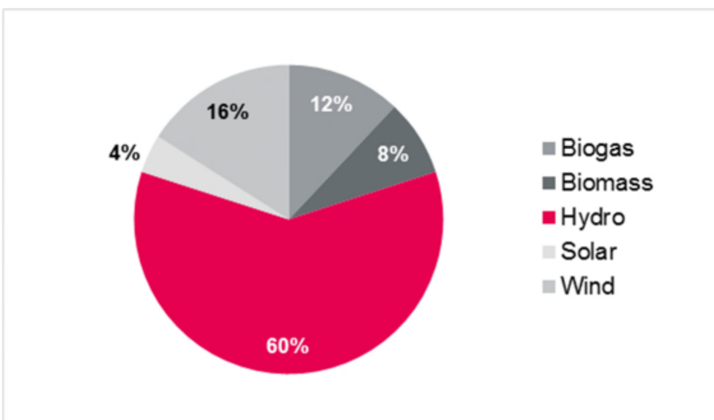
SUSPENSION OF STANDING OFFER PROGRAM AND MICRO-STANDING OFFER PROGRAM

On August 18, 2017, BC Hydro announced that it was suspending receipt of new applications for the Standing Offer Program (SOP) and Micro-Standing Offer Program (Micro-SOP), until a review of the programs is completed with input from the Province and Clean Energy BC, an industry organization that represents independent power producers (IPPs). Applications received prior to August 18, 2017 will continue to be processed and placed in the queue if the key requirements are met. BC Hydro indicated in its announcement that the review of the SOP and Micro-SOP was taking longer than originally anticipated and that it was not known when the review will be completed.

Prior to the suspension, the SOP and the Micro-SOP, which were open to projects with a capacity between 1 MW and 15 MW in the case of the SOP and 100 kW and 1 MW in the case of the Micro-SOP, were BC Hydro's only active procurement opportunity for IPPs.

Overview of Awarded SOP EPAs and SOP and Micro-SOP Applications

In March 2017, BC Hydro released an updated list of current SOP electricity purchase agreements (EPAs) and SOP applications showing 26 EPAs awarded and 14 accepted applications. Five of the EPAs were awarded in 2016 in respect of the Clemina Creek Hydro Project, the Hunter Creek Run-of-River Hydroelectric Power Project, the Serpentine Creek Hydro Project, the Winchie Creek Hydro Project and the Lorenzetta Creek Hydroelectric Project. No EPAs were awarded between January 1, 2017 and the announcement of the updated list on March 31, 2017. A breakdown of the current SOP EPAs by energy source is set out below:



The 14 accepted SOP applications provide for an aggregate capacity of 137 MW. All will have Target COD years of 2019 or earlier, as BC Hydro will not assign volume for years 2020 and beyond until the review of the programs is complete. Seven of the accepted SOP applications are for hydroelectric projects, while five are for wind projects, and the remaining two are for a solar project and a tidal power project.

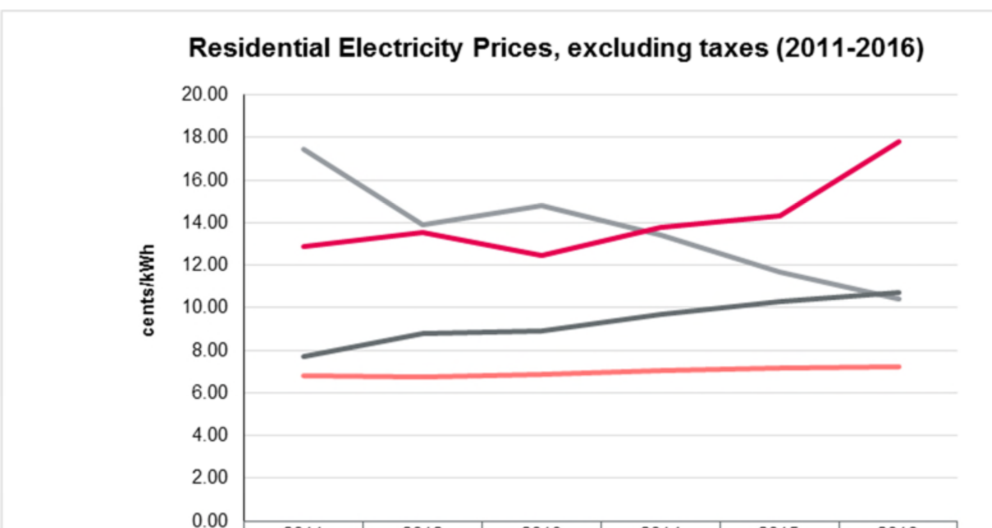
No EPAs had been awarded under the Micro-SOP as of March 31, 2017. The three applications accepted were for the Tsilhqot'in Solar Farm, the Seabreeze Agri-Energy Biogas Project and the Siwash Creek Hydro Project.

BCUC REVIEW OF BC HYDRO RATE DESIGN APPLICATION

On September 24, 2015, BC Hydro filed its 2015 Rate Design Application with the BCUC (the RDA), which represented the first comprehensive review of BC Hydro's rates since 2007. Over the course of 2016, the BCUC received submissions from a variety of interested parties, including various advocacy groups who argued in favour of measures to assist low income individuals such as reduced rates and delayed disconnection.

Key details of the BCUC RDA decision released on January 20, 2017 include:

- maintaining the current two-tier residential rate structure, the elimination of which would have resulted in increased utility bills for most residential customers;
- simplifying commercial rates by eliminating two and three-tiered rates that were considered to be too complex and difficult for customers to understand;
- denying the request for special rates for low income individuals as the BCUC determined that it did not have legal jurisdiction to create a specific rate for such individuals. However, the BCUC approved a number of measures that will benefit low-income individuals, including reduction of the minimum reconnection charge, directing BC Hydro to develop an assistance program for individuals unable to pay their utility bills, and directing BC Hydro to work with advocacy groups to determine further measures that may assist low income individuals; and
- approving a Freshet Rate program for industrial customers as a two-year pilot program. Such program will make a lower rate available to industrial customers during the May-July freshet period in order to assist BC Hydro in managing oversupply of energy during that period and reduce the export of electricity to the market at low prices.



	2011	2012	2013	2014	2015	2016
Montreal, QC	6.82	6.76	6.87	7.06	7.19	7.23
Calgary, AB	17.47	13.89	14.81	13.41	11.66	10.40
Toronto, ON	12.90	13.57	12.48	13.78	14.31	17.81
Vancouver, BC	7.68	8.78	8.91	9.71	10.29	10.70

What to Expect in 2018

2018/2019 Rate Freeze and BC Hydro Review

A key policy commitment of the incoming Provincial Government was to freeze BC Hydro's residential rates in 2018 pending a comprehensive, year-long review of BC Hydro and its operations. Accordingly, the 3% rate increase contemplated for 2018 under BC Hydro's 10 Year Plan will be cancelled, resulting in an approximately $150 million revenue shortfall. The Government hopes to offset this revenue loss in part through cost savings to be identified as part of its review of BC Hydro, the first such review since 2011.

BC Hydro 2018 Integrated Resource Plan

BC Hydro is scheduled to update its Integrated Resource Plan (IRP) – the long-term plan to meet the Province's future electricity demand through conservation, generation and transmission, and through upgrades to existing infrastructure – in 2018. Last prepared in 2013, the IRP will need to address significant changes in the energy market as well as the emerging energy policy priorities of the new Provincial Government, which has signaled that the 2018 IRP will follow its own comprehensive review of BC Hydro.

BC's Energy Road Map and Future Drivers of Renewable Energy in BC

A key element of newly-appointed BC Energy Minister Michelle Mungall's mandate is the creation of a "roadmap" for the future of BC energy that will "drive innovation, expand energy-efficiency and conservation programs, generate new energy responsibly and sustainably, and create lasting good jobs across the province."

In constructing such a road map, the Province has identified climate change strategies being adopted by various levels of government as a key driver of electricity demand, which it estimates will grow by 10,000 GWh by 2050. These include the Federal Government's commitment to reduce greenhouse gas emissions by 30% by 2030, BC's own commitment to reduce greenhouse gas emissions to 80% below 2007 levels by 2050, and commitments by BC municipalities to rely solely on renewable energy by 2050.

Given these and other climate policy initiatives, and BC's current reliance on natural gas and oil to meet over 60% of its energy needs, the Province expects the fuel switching required to meet carbon reduction targets to be a key contributor to electricity demand. Other contributors will be increasing adoption of electric vehicles in both the consumer and industrial sectors, increased electrification of buildings and related space and water heating and increasing industrial electrification, particularly in upstream natural gas processing.

LNG Final Investment Decision – Maybe

LNG projects continue to face uncertainty in 2018 given the difficulties faced by the global energy industry as a whole. Of those remaining, the most significant is the LNG Canada project. A final investment decision for the LNG Canada project may be announced in 2018.

EPA Renewals

As we noted last year, fourteen of BC Hydro's EPAs with IPPs will expire by the end of 2019. BC Hydro has indicated that it will be pursuing EPA renewals on a cost-of-service basis, which will favour those IPPs which provide the lowest cost, greatest certainty of continued operations and best system support. In renegotiating EPAs, BC Hydro will consider, among other things, the opportunity cost of the IPPs, the electricity spot price, and the cost of service for the IPPs. Based on the assumption that IPPs will have fully recovered their capital expenditures during the initial term of their EPAs, BC Hydro expects to negotiate lower energy prices when renewing EPAs. BC Hydro estimates that it will be able to acquire power under renewed EPAs at or below $85/MWh, although the actual energy price under each renewed EPA will be the subject of negotiations between BC Hydro and the applicable IPP.

BC Hydro has stated that it plans to acquire through renewed EPAs 50% of the energy and capacity contributions of existing bioenergy EPAs and 75% of the contributions of the existing run-of-river hydroelectric EPAs that are due to expire by 2024.

Alberta

Cameron Hughes

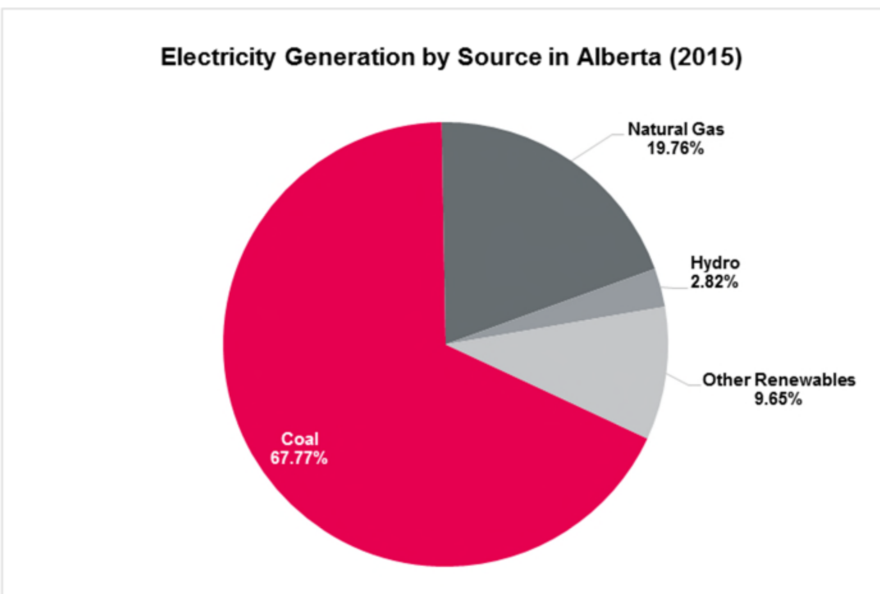
Kimberly Howard

Scott Bergen

Niki Gill

Introduction

Alberta's electricity industry is in a state of transition. The main policy drivers for the electricity market transition include: (i) Alberta's implementation of the Climate Leadership Plan (Climate Plan) originally announced in November of 2015; (ii) market restructuring from a fully deregulated regime to a hybrid market incorporating capacity payment mechanisms; and (iii) the phasing-out of emissions from coal-fired generation by 2030. Among other things, the Climate Plan promised an economy-wide carbon price, a legislated cap on oil sands emissions and set goals for the phase-out of coal-fired generation by 2030. As of January 1, 2018, a $30 per tonne carbon levy was applied to fuels that emit greenhouse gas when combusted. A more detailed discussion of each of these Climate Plan initiates can be found in the Environmental Law Section of this publication.



Source: Environment Canada, National Inventory Report 1990-2015: Greenhouse Gas Sources & Sinks in Canada

Alberta remains one of the few jurisdictions in the world with an "energy-only" market. For the time being, transmission and distribution in Alberta is regulated, while the generation and retail sale of electricity is open to competition. The market is a real-time, energy-only equilibrium market, or power pool. The Alberta Electric System Operator (AESO) is responsible for facilitating a fair, efficient and openly competitive market and for the safety and reliability of the electricity grid. The following sections describe several key developments in the transition of Alberta's electricity industry.

Key Developments in 2017

IMPLEMENTATION OF CAPACITY MARKET

Over the next 14 years, the Province estimates that it will need up to $25 billion of new investment in electricity generation to support, in part, the growing electricity needs of the Province and to implement the Province's plan to phase-out coal-fired generation and meet its target of 30% renewable electricity capacity by 2030. In order to achieve this, the Province intends to support 5,000 MW of additional renewable capacity.

Accordingly, the AESO recommended that Alberta implement a capacity power market regime, which is expected to promote stability in the price and supply of electricity and investment in energy. This recommendation can be found in the AESO's report entitled Alberta Wholesale Electricity Market Transition Recommendation.

Under the proposed market scheme, Alberta will incorporate mechanisms to compensate power producers for their generation capacity. Alberta's electricity market will therefore be comprised of three separate markets: (i) the existing market for energy; (ii) the existing market for ancillary services market; and (iii) a new market for capacity in which generators will agree to have availability to supply electricity when required.

Why the Implementation of a Capacity Market

By letter dated January 10, 2017, Alberta Energy requested that the AESO lead the technical design of the capacity market, including an evaluation of the AESO itself in order to identify necessary charges to the energy and ancillary services products markets, to ensure system reliability.

Within the AESO Capacity Report, the AESO concluded that maintaining the status quo (i.e. no change to the current energy-only market rules, products or design) will not attract a sufficient amount of investment in firm, dispatchable generation to ensure an adequate supply as Alberta transitions away from coal to renewable generation.[1] At a high level, Alberta Energy and the AESO's desired outcomes are:

- a **reliable and resilient system** (compatibility with managing coal phase-out, compatibility with increased interties, integration of renewable generation and new technologies, variability of the reserve margin and sufficient supply adequacy);
- **environmental performance** (compatibility with the REP (see below), resiliency of market to environmental policy, compatibility with increased cogeneration, energy efficiency, micro and distributed generation, carbon prices and future expansion of renewable energy);
- **reasonable costs to consumers** (stable prices, reasonable cost of delivered energy, maintaining fair efficient and openly competitive market operation, compatibility with changes to the regulated rate option, maintaining reasonable transmission costs);

[1] AESO Capacity Report at 16.

- **economic development and job creation** (impact on trade exposed or key industries, enabling economic growth and achieving other social objectives such as support for particular demographics, locations or industrial policy); and
- an **orderly transition** (minimizing disruption and costs).

As discussed in detail within the AESO Capacity Report, the AESO ultimately recommended a capacity market because it achieved the foregoing outcomes.[2]

Timeline for the Capacity Market and SAMs

Alberta's capacity market will be developed in consultation with stakeholders. The AESO formed five working groups with broad industry representation and tasked members with developing recommendations for the key design elements presented in the Straw Alberta Market (SAM) 1.0. The working groups' progress on developing recommendations was reported in SAM 2.0 in late August. On December 6, 2017, the AESO published the SAM 3.0 Stakeholder Update. Key provisional recommendations set out in SAM 3.0 indicate a one year capacity delivery obligation period for all resource types. This is a key capacity market design consideration. Stakeholder feedback is to be posted by the AESO in January, 2018. SAM 3.0 provisional recommendations will be considered by the AESO as it develops a draft comprehensive market design, anticipated to be released mid-2018. The first auction for the capacity market will launch in the fourth quarter of 2019, with the first delivery period starting in 2021.

PHASE-OUT OF COAL EMISSIONS BY 2030

Emissions from coal-fired power generation in Alberta are to cease by 2030 either through the retirement of generation units or by owner action to fully sequester carbon dioxide. The Climate Plan's goal is to replace these units with two-thirds renewable energy and one-third natural gas generation. The Province legislated its "30 by '30" target in the *Renewable Electricity Act*, proclaimed in force on March 31, 2017. The initiatives by the Province are in line with the Federal Government's objective to transition from coal power to clean energy by 2030. Under the federal regulations twelve out of Alberta's eighteen coal-fired generating units will retire before 2030. To comply with both federal and provincial regulations, Alberta's six remaining coal-fired generating units will be phased out by 2030.

In November 2017, the Province concluded its Advisory Panel on Coal Communities (Advisory Panel) which met with workers and community members. One of the initiatives arising out of the Advisory Panel's Recommendations to the Government of Alberta is a $40-million Coal Workforce Transition Fund to provide income support to workers transitioning from working in Alberta thermal coal mines and coal-fired generation plants to new jobs or retirement.

a) Transition Payments for Coal Generators

In November 2016, the Province reached agreements with the facility owners of coal-fired units with operating lives beyond 2030, being TransAlta Corporation (TransAlta), Capital Power Corporation (Capital Power), and ATCO Ltd. (ATCO), to provide transition payments as part of the coal phase-out process.

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[2] AESO Capacity Report at 40-41.

Under the proposed scheme, TransAlta, Capital Power, and ATCO are expected to receive payments totaling $1.1 billion over the course of 2016 to 2030. The Province announced that these payments will not be funded by consumer electricity rates, but rather by the Alberta's carbon levy on industrial emissions. The payments represent the approximate disruption to the capital investments of these facility owners.

b) Power Purchase Arrangements (PPAs) Litigation

The PPAs were the chosen mechanism in 2001 to transition the Alberta electricity market from a cost-of-service market to the current energy-only model. The PPAs are statutory arrangements imposed by regulations under Alberta's *Electric Utilities Act* to allow their holders to buy output from the coal-fired generation facility owners and bid it into the power pool. PPAs have recently declined in profitability for their holders as a result of increased costs attributed to Alberta's regulation of greenhouse gas emissions and lower revenues resulting from falling power pool prices.

Before the *Climate Leadership Act* became law, PPA holders gave notice of their intention to terminate their PPAs under their "Change in Law" provisions. These provisions, dubbed the "Enron Clause" by the Province, allow the PPA holder to terminate the PPA without penalty if a Change in Law renders the PPA "unprofitable or more unprofitable." In December 2015, ENMAX was the first to announce that it was terminating its PPA with the owner of the Battle River 5 coal plant subject to the PPA. The Balancing Pool accepted the termination of the Battle River PPA in accordance with its terms. To date, this is the only termination that has been formally accepted. The Balancing Pool's acceptance of the other PPA terminations is pending.

Controversy arose as the Province disputed the effectiveness of the Enron Clause, essentially on a procedural basis. The Province filed an application seeking a declaration from the courts as to the validity of the Enron Clause. Specifically, it contends that in 2000 during the process of finalizing the PPAs but before their "auction", a request was made on behalf of Enron to add the phrasing "or more unprofitable" to the Change in Law provision. This added language broadly increased the discretion of the PPA holders to terminate their respective PPAs. The form of PPAs that had been approved by previously held public hearings were granted such amended phrase by the Energy Utilities Board of Alberta without public notice or hearing. The Province is arguing that the last-minute amendment to the PPA was void from the outset because it was done without proper consultation or review, and thus there was no authority to amend the PPAs in that fashion. The Province's strategy appears to be that if the words "or more unprofitable" are found by the court to be invalid, the PPA holders will not have met the condition necessary to allow the Balancing Pool to accept the termination of the PPAs and will, therefore, need to continue performing their contractual obligations.

In addition to the Province's application for a judicial declaration, the resolution of disputes under the PPAs has progressed along a number of other different courses, including by way of:

- negotiations between the Province and buyers respecting terms of termination of PPAs;
- while the right to terminate the PPAs remains an issue, in October 2017, the Alberta Court of Queen's Bench granted ENMAX its requested declaratory relief that the effective date of termination of the Battle River PPA (respecting Battle River 5 coal plant) is January 1, 2016; and
- arbitrations commenced by TransCanada Energy and ATSC Power Partnership respecting their entitlement to terminate PPAs associated with the Sundance A, Sundance B and the Sheerness coal plants.

To date, the Province has reached final agreements with Capital Power, AltaGas Ltd. and TransCanada Energy Ltd. respecting litigation over the PPAs. Accordingly, these companies will be removed from the court proceedings initiated by the Province. The outcome of the PPA disputes remains uncertain, and it will be interesting to see whether the courts and arbitrators will hear these matters before settlements are reached, and if so, whether they will reach consistent decisions.

INCENTIVES FOR RENEWABLE ENERGY GENERATION

1. AESO's Renewable Electricity Program

The Province tabled the *Renewable Electricity Act*, legislating its "30 by '30" target and providing powers to the AESO to administer a competitive bid process for its Renewable Electricity Program (REP). Under the REP, successful bidders enter into a Renewable Electricity Support Agreement (RESA) with the AESO, which will provide a 20-year indexed renewable energy credit, structured akin to a contract for difference (CFD), to cover any difference between the participant's bid price for the project and the pool price of energy in the market.

Competitive Procurement Process

Each REP Round consists of three stages:

i. Request for Expressions of Interest: 4-6 weeks

- Interested parties determine whether to participate in the competition. There is no obligation on interested parties to participate at this stage.

ii. Request for Qualifications (RFQ): 4-6 months

- Bidders meeting certain eligibility requirements submit their qualifications and pay a qualification fee to participate in the bid.

iii. Request for Proposal (RFP): 2-3 months

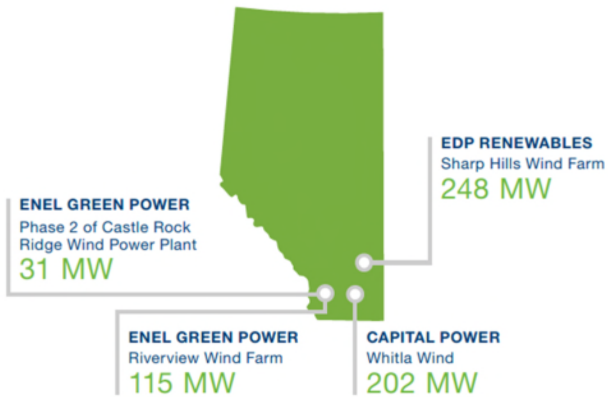
- Qualified RFQ bidders submit their final binding offer for support (i.e. bid price).

Following the closing of a REP Round, the results must be approved by the Minister. After this, the successful bid participants will enter into a RESA with the AESO.

First Competition – Round 1

The first competition of REP (REP Round 1) opened on March 31, 2017 and concluded on December 13, 2017 when the Province announced the results of Round 1 of the REP. The successful bids set a record for the lowest renewable electricity pricing in Canada, ranging from $30.90 to $43.30 per MWh with a weighted average price for the successful bids of approximately $37 per MWh or 3.7 cents per kWh.

REP Round 1 delivered more than the anticipated 400 MW with almost 600 MW of wind generation from the following four projects:



Source: AESO, REP Round 1 Infographic (13 December 2017), online: https://www.aeso.ca/market/renewable-electricity-program/rep-round-1-results/

The AESO released the final form of the Renewable Electricity Support Agreement (RESA) in January 2018, and also provided a Fairness Advisor's Report for REP Round 1. P1 Consulting Inc., acting as the Fairness Advisor concluded that up to December 8, 2017, REP Round 1 was undertaken in a fair and transparent manner. Twelve proponents submitted bid prices for 26 projects (representing 3,600 MW of capacity) in the RFP stage of REP Round 1.

Future Competitions – REP Round 2

In its report titled Renewable Electricity Program Recommendations, the AESO provided a framework for the bidding process for future auctions, including project eligibility criteria. The AESO stated that, at the RFQ stage of the procurement process, bidders must pay a non-refundable qualification fee and demonstrate their qualifications in the following three categories: project eligibility, financial strength and capability, and technical capability. These are minimum requirements and additional eligibility criteria may be introduced as seen in the specific requirements set out for REP Round 1. Further, Alberta's Minister of Environment left it open for future competitions to weigh Indigenous participation or project location more heavily than cost considerations.

To date, the timing of REP Round 2 has not been finalized. More details are expected in early 2018. With stunningly low prices, we anticipate the Province will seek to launch Round 2 as soon as possible to continue progressing toward its 30 by '30 target. Whether such low prices can be sustained or replicated in future rounds will depend upon the evaluation factors and project criteria (e.g. geographic, Indigenous participation or municipal involvement) identified in each round by the Province. Each of the REP Round 1 projects can be connected to the existing transmission system with no new transmission costs or upgrade requirements; however, Alberta's 30 by '30 target cannot be achieved solely through such selection criteria. As a result, Albertans should not to treat these very low prices as the market benchmark.

2. Other Renewable Generation Incentives

In addition to REP, Alberta also implemented a number of solar programs, including:

- **Alberta Infrastructure's Negotiated Request for Proposals for Solar (NRFP):** Separate and apart from REP, the NRFP was first announced in October 2016 for two contracts with total consumption of 135,000 megawatt hours a year. While the NRFP process was commenced in the Spring 2017, the process has been delayed;

- **Alberta Indigenous Solar Program:** Provides grants to Alberta Indigenous communities or Indigenous organizations to install solar PV systems on facilities owned by the community or organization;
- **Alberta Municipal Solar Program:** Provides financial incentives to Alberta municipalities who install grid-connected solar PV on municipal facilities or land. All projects under this program must be completed and energized after February 5, 2016; and
- **Commercial and Residential Solar Program:** Program offers rebates to homeowners, businesses and non-profits that install solar PV systems.

CONSUMER PROTECTION

In 2017, the Province implemented the following initiatives targeted at ensuring low and stable electricity prices for consumers.

Amendments to the Balancing Pool

Pursuant to section 96 of the *Electric Utilities Act,* a PPA that has been terminated and such termination has been accepted by the Balancing Pool is deemed to have been sold to the Balancing Pool. The Balancing Pool then has the statutory option to hold the PPA, resell it, or terminate it by paying the generator an amount equal to the net book value of the generating unit. If the Balancing Pool maintains the PPA, it becomes responsible for offering the capacity into the market and making payments under the PPA to the generator. By taking over the PPAs, the Balancing Pool would have to pay power producers the same amount that PPA buyers would have, and the result is that the Balancing Pool would risk having insufficient funds.

Currently, the Province reports that the average electricity consumer receives a Balancing Pool credit of $1.95 on their monthly bill. However, if the Balancing Pool becomes responsible for the terminated PPAs, it is expected that the Balancing Pool would have to remove that credit and apply a charge of $8.40 per month (approximately $100 per year) starting January 1, 2017, with similar charges applied until the end of 2020.

Late in December 2016, the Province enacted the *Electric Utilities Amendment Act, 2016*, which among other things, allows the Balancing Pool to borrow money from the Province to manage its funding obligations, smoothing price volatility over a longer period of time to provide more stability in electricity costs for consumers. Additionally, this Act gives the Balancing Pool until 2030 to meet its net zero obligations. As a result of these amendments, it is estimated that the Balancing Pool's charge would instead be 67 cents per month for the average consumer or $7.73 less per month than if the Province had not intervened.

Effectively, the *Electric Utilities Amendment Act, 2016* ensures that the Balancing Pool can meet its financial obligations without consumers shouldering an immediate and disproportionate increase to electricity bills. Presently, the Province has not announced the total amount of the loans that will be made to the Balancing Pool and thus the final cost of this initiative to tax payers remains to be determined.

Price Cap on Electricity Prices

On July 12, 2017, the Province enacted *An Act to Cap Regulated Electricity Rates* to implement a price-cap of 6.8 cents per kilowatt hour from June 1, 2017 to May 31, 2021. Consumers on the Regulated Rate Option (RRO) will pay the lower of the market rate and such capped rate. Electricity prices for most RRO customers are established by Alberta Utilities Commission approved price-setting plans.

We understand that the intention of the Province is to protect consumers in anticipation of future price volatility. The price cap will apply only to the energy portion of a consumer's bill and no details have been provided about how these changes will affect distribution and transmission prices. Further, no details were provided regarding what effect the cap will have on existing retail fixed rate contracts that fix consumers' rates above the 6.8 cent cap. The price cap will affect the competitive retail electricity market in Alberta by providing an alternative to retail contracts.

Please refer to our table respecting Retail Electricity Prices across various municipalities in Canada, in the BC Region section.

Door-to-Door Ban

As of January 1, 2017, selling household energy products unsolicited door-to-door was prohibited though changes to Alberta's *Fair Trading Act* and its regulations. The prohibition applies to unsolicited sales of household energy products only and, specifically, furnaces, natural gas and electricity energy contracts, water heaters, windows, air conditioners and energy audits. The Province made it clear that the ban is targeted at door-to-door sales, and energy companies can still sell directly to customers through other means, including telephone, online sales, kiosks and advertising.

MARKET RULE DEVELOPMENTS

Revocation of the OBEG

On May 26, 2017, the MSA revoked the *Offer Behaviour Enforcement Guidelines* (OBEG) on the grounds that an emerging capacity market in Alberta may mean that offer behaviour that previously promoted dynamic efficiency may no longer outweigh losses in static efficiency. OBEG provided guidelines that suggested offer behaviours such as economic withholding should not be subject to enforcement action. The revocation of OBEG does not mean that the practice of economic withholding will necessarily be prohibited moving forward. Instead, market participants will need to proceed with caution to ensure that employment of offer behaviour strategies to increase market prices do not attract enforcement action. Market participants engaging in offer behaviour strategies based on increasing pool prices may attract enforcement action if those offer behaviour strategies are considered by the AUC to be price manipulation[3] or by the MSA if they may have a deleterious effect on market outcomes[4]. While OBEG previously offered a mechanism by which to justify strategies that would otherwise fall under this prohibition, removal of OBEG means that the process of economic withholding in order to increase pool prices is no longer afforded exemption from enforcement action.

New ISO Rules and ISO Rule Amendments

Following announcement of the REP, the AESO conducted a series of consultations for the AUC in respect of the independent system operator rules (Rules). Prior to the amendments discussed below, the Rules did not contain technical or operating requirements for solar aggregated generating facilities. Additionally, the AESO determined that the Rules relating to wind aggregated generating facilities required revision to align with amendments to Section 502.5 *(Generating Unit Technical Requirements)* and Section 502.6 *(Generating Unit Operating Requirements)* of the Rules, which came into effect on November 21, 2017.

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[3] *Fair, Efficient and Open Competition* Regulation, ss.2(j).
[4] MSA, Notice of Consultation re Revocation of Offer Behaviour Enforcement Guidelines (12 March 2017)

The result of the consultation process was a set of amendments collectively known as the "Wind, Solar, AGF and DER Rule Amendments and Definition Amendments" (the Amendments). The Amendments are expected to become effective in the second quarter of 2018 once required changes to the AESO's IT systems have been completed.

Highlights of the Amendments include:

- certain technical revisions to the Rules to include the concept of "solar aggregated generating facilities";
- substantive changes to Section 304.3 (*Wind and Solar Power Ramp Up Management*) relating to the procedures surrounding power limit pro rata shares and the interaction between the market merit order provisions of the Rules and pro rata shares;
- the addition of Section 304.9 (*Wind and Solar Aggregated Generating Facility Forecasting*) as a new section of the Rules addressing the forecasting requirements for an aggregated generating facility;
- substantive changes to Section 502.1 (*Aggregated Generating Facilities Technical Requirements*) and Section 502.8 (*SCADA Technical and Operating Requirements*) relating to specific operating requirements of aggregated generating facilities and synchronous generating units; and
- the addition of Section 502.16 (*Aggregated Generating Facilities Operating Requirements*) as a new section to the Rules addressing the key requirements to operate and maintain an aggregated generating facility.

Into 2018 and Beyond

Significant changes to Alberta's generation mix are ahead, and with such changes come uncertainty. The economic downturn, continuing lack of detail respecting aspects of the Climate Plan's implementation and the outcome of the PPA litigation contribute to the state of uncertainty in the Province. Regulatory uncertainty creates challenges for the forecasting of load, generation and economic growth in Alberta, and policy announcements have affected such predictions even as of July 2017 when the AESO 2017 Long-term Outlook was published.

Implications from the overhaul of Alberta's power market will need to be considered in light of other regulatory changes recently announced by the Province. It will be critical to watch how the capacity market will interact with the principles of the energy-only market and how the principles legislated within the *Fair, Efficient and Open Competition Regulation* will be applied to the various relationships between generators participating in the Alberta market, including the successful bidders from the REP and the auction for capacity contracts, and how such incentives will be addressed with incumbent generators who already invested, built and operate natural gas and renewable generation facilities in Alberta.

Ontario

Seán C. O'Neill | **James Klein** | **George Vegh** | **Zachary Masoud** | **Brianne Paulin**

Introduction

In 2017, Ontario's power sector was marked less by new procurements than by a focus on costs and maximizing the use of existing assets. A new long term energy plan focused on energy affordability, market renewal, innovation and customer choice, the continued development of energy storage and the cap-and-trade program, and continuing progress with the Province's plan to reshape the electricity market through market renewal and capacity markets. This is the first planning process since Bill 135, the *Energy Statute Law Amendment Act, 2015* , was enacted and the main focus will be on the implementation plans of the Ontario Energy Board (OEB) and the Independent Electricity System Operator (the IESO).

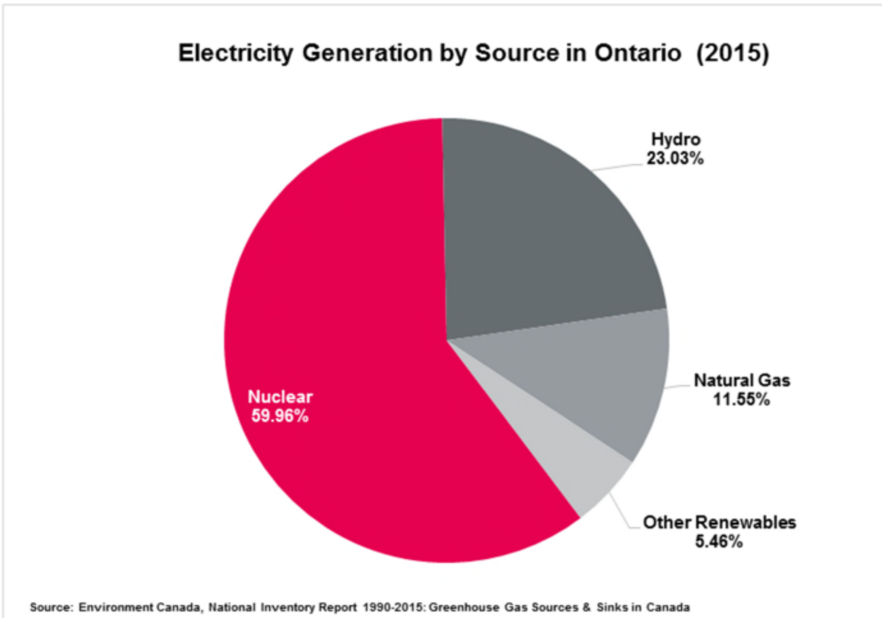
Closely tied to the June 2018 election is the Fair Hydro Plan (FHP), which reduces electricity bills for residential customers by an average of 25%, limits bill increases for the next five years and defers the recovery of electricity costs into the post-2022 environment (just in time for the next election). Please refer to our table respecting Retail Electricity Prices across various municipalities in Canada, in the BC Region section.

LONG-TERM ENERGY PLAN

On October 26, 2017, the Ministry of Energy released Ontario's revised *2017 Long-Term Energy Plan*, *Delivering Fairness and Choice* (the LTEP), which includes predictions as far as 2035 and provides an overview of Ontario's goals and objectives.

For renewable energy, the LTEP highlights that between 2026 and 2035, contracts for over 4,800 MW of wind energy, 2,100 MW of solar energy, and 1,200 MW of hydroelectric generation will expire. The LTEP also notes the Province's wind and solar energy facilities can be upgraded with new or more efficient technology so that these facilities can continue operating, increase their output and provide additional system benefits. This will maximize value from existing assets. Under the LTEP, the spotlight continues to shine on nuclear power. Ontario confirmed its plan to move forward with the refurbishment of ten nuclear units, four at Darlington Nuclear Generating Station and six at Bruce Nuclear Generating Station, between 2016 and 2033 as previously outlined in the 2013 Long-Term Energy Plan. The LTEP notes that refurbishing these 10 units will secure more than 9,800 MW of capacity. Notably, the refurbishment of Darlington Nuclear Generating Station by Ontario Power Generation is expected to inject $90 billion into Ontario's economy and increase employment by an average of 14,200 jobs annually. The refurbishment by Bruce Power of the six nuclear units at Bruce Nuclear Generating Station remaining to be refurbished is expected to contribute up to $4 billion to the economy and increase employment by an average of 22,000 jobs annually.

The LTEP did not just focus on the segments of the supply mix that usually get attention, however. Energy storage, discussed below, has received new-found prominence. Other initiatives noted in the LTEP include Ontario's plan to modernize transmission and distribution of electricity through a smart grid that will allow customers and utilities to make optimal decisions related to consumption of electricity. Ontario is also reviewing projects in several jurisdictions that pilot transactive energy and blockchains. Notably, the IESO has been directed by the Ontario Government to develop a competitive selection or procurement process for transmission to identify potential pilot projects.



ENERGY STORAGE

In 2017, Ontario reiterated its commitment to innovation and development of energy storage in the LTEP. Since the 2013 LTEP, Ontario has procured 50MW of energy storage capacity through a two-phase competitive energy storage procurement process launched by the IESO in 2014. Ontario has further committed to researching the potential of energy storage and its benefits to consumers as well as identifying regulatory barriers for market entry and adoption of energy storage technologies. Ontario continues to work with industry and agency partners to identify regulatory barriers.

In the LTEP, the Ontario Government issued implementation directives to the IESO and the OEB to "review market rules, industry codes, and regulations, in order to identify potential obstacles to fair competition for energy storage with other technologies in the delivery of services and, where appropriate, propose mitigation strategies". On October 24, 2017, the Ministry of Energy proposed amendments to Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) under the *Electricity Act, 1998* to define energy storage and adjust the treatment of the global adjustment for Class B energy storage facilities. In its proposed regulation, the Ministry of Energy defines energy storage to "address the unique characteristics of these facilities, such as their ability to provide services to Ontario's electricity grid". The proposed regulations will take effect on July 1, 2018.

Even though developments in energy storage in Ontario have been slow-moving, the market for energy storage in Ontario continues to grow rapidly. Ontario's commitment to reduce market barriers for energy storage technologies is implicit recognition that government intervention is necessary to level the playing field with other renewable technologies. Projects from Phase I of the energy storage procurement process are expected to become operational by the end of 2017.

In 2017, the IESO launched a Regulation Service Request for Proposals to procure 50 MW of incremental storage capacity. The IESO awarded two contracts representing 55 MW across two new energy storage facilities. By selecting two energy storage facilities to support the reliability, flexibility and efficiency of the system, the IESO implicitly recognized that energy storage facilities can serve multiple functions, including generation supply, electrical load and system reliability.

CAPACITY MARKET / MARKET RENEWAL

In 2017, Ontario moved forward with its plan to reshape its electricity market through market renewal and the introduction of capacity markets (Market Renewal). In the LTEP, Ontario confirmed that it will be moving away from long-term energy contracts and instead will focus on developing a capacity market with goals of flexibility and efficiency. Through the Market Renewal initiative, the IESO is studying how it can procure – through competitive mechanisms – new supplies of energy as the Province's needs are identified. Ontario expects that this approach will result in a more competitive, flexible and efficient system that could reduce costs to ratepayers by $5.2 billion between 2021 and 2030. The design of the market underpinning Market Renewal will address three streams identified by the IESO: energy, capacity and operability.

Since 2016, the IESO has been consulting with stakeholders on a work plan for reviewing Ontario's electricity market. On September 28, 2017, the IESO announced that it will begin consultations for the design of a Day Ahead Market and an Enhanced Real Time Unit Commitment Program as part of the Market Renewal initiative. Ongoing consultations on capacity exports and system flexibility have also been incorporated into the Market Renewal initiative.

The IESO further commissioned a report (the IESO Report)[5] to study the benefits to Ontario of implementing a capacity market and to determine whether to proceed with the Market Renewal. The IESO Report was published in March 2017 and found that the benefits to Ontario of such implementation outweighed the costs, with "a ten-year present value of net benefits ranging from $2,200 million to $5,200 million" shared by customers and suppliers. The report noted that, as long-term energy contracts expire and as the capacity market becomes competitive and incorporates new technologies, the benefits of the capacity market will increase.

An interesting question will be whether the proposed capacity market will be technology neutral, which the IESO proposes and which is the basis for the reduced future procurement costs, or whether the Ontario Government continues to determine which supply resources are to be purchased.

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[5] The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project, April 2017.

CAP AND TRADE

In 2017, Ontario's cap-and-trade program became operational as an Ontario-only market. The cap-and-trade program limits the amount of emissions that certain companies can emit. If the companies exceed those limits, they must buy emission allowances at a cap-and-trade auction or from other companies that have not reached their limit. Under Ontario's program, auctions must be held four times each year for the 2017-2020 compliance period. In 2017, the auctions were held on March 22, June 6, September 6 and November 29. The March 22, June 6, September 6 and November 29 auctions brought in $472 million, $504 million, about $526 million and $422 million respectively. This puts the Province on track to reach its prediction that the cap-and trade-program will generate $1.8 billion per year in proceeds. All four auctions sold out of their respective current emissions allowances.

Pursuant to the Climate Change Action Plan, Ontario must invest the proceeds of the auctions in programs that will reduce greenhouse gas pollution or help businesses reduce their own emissions. The proceeds from the 2017 auctions held thus far have been invested in Green Ontario Fund, projects to repair and provide social housing, and initiatives to support municipalities in fighting climate change.

On September 22, 2017, Ontario signed a linkage agreement with Québec and California enabling the three jurisdictions to hold joint auctions as of January 1, 2018. This arrangement will create the second largest carbon market in the world and will facilitate joint auctions of Ontario, Québec and California's emission allowances. Emission allowances bought through the joint auctions can be used in any of the jurisdictions. To facilitate the implementation of the linkage agreement, Ontario has also proposed changes to the *Cap and Trade Program Regulation* and the *Methodology for Distribution of Ontario Emission Allowances Free of Charge*. These changes will harmonize reporting requirements, recognize California and Québec's compliance instruments, and ensure a common accounting mechanism in calculating each jurisdiction's share of emission reductions[6].

For more discussion on Ontario's cap-and-trade program, please refer to the Ontario cap-and-trade program portion of the Environmental Law section in this publication.

ONTARIO'S FAIR HYDRO PLAN

On March 2, 2017, Ontario announced the FHP, which took effect on July 1, 2017. The FHP immediately reduces electricity rates for consumers by 25% and limits the increase in electricity rates to the rate of inflation for four years. In the long-term, rates will increase to pay the debt accrued to reduce hydro bills. According to the Financial Accountability Office of Ontario, the FHP will cost the Province $45 billion over a 30 year period while providing savings to ratepayers of $24 billion, which results in a net cost of $21 billion to Ontarians.[7]

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[6] Financial Accountability Office of Ontario, Media Release, "Fair Hydro Plan Provides Temporary Electricity Bill Relief but Higher Bills by 2028" (24 May 2017), online: <http://www.fao-on.org/en/Blog/media/Fair_hydro_MR>.
[7] *Ibid*

Predictions for 2018

The Ontario provincial election is expected to be held in June 2018. As we highlighted in our publication last year, developers having obtained contracts in the Large Renewable Procurement I (LRP I) process will look to commence or accelerate construction in the event that the termination for convenience clauses are triggered post-election. Due to the uncertainty of the post-election viability of the LRP I contracts, developers will want to ensure that construction begins before the election and that projects currently under construction are accelerated to ensure that milestones are met. Although the average price of the LRP I contracts is significantly lower than most of Ontario's earlier wind contracts, the comparatively low prices from the recently completed procurement in Alberta will likely attract negative attention from opposition parties.

On December 1, 2017, the IESO's microFIT Program reached its 50 MW Annual Procurement Target for 2017. As a result, the IESO will no longer be accepting applications for the microFIT Program. In the LTEP, the Ministry of Energy highlighted plans to enhance the net metering program by providing more opportunities for consumers and businesses to store and generate energy. Since the IESO is no longer accepting applications for the microFIT Program, developers interested in small-scale renewable generation will need to consider whether proposed changes to net metering will be sufficient to create opportunities with local distribution companies or otherwise.

While there seems little likelihood that we will see new procurement for generation projects using long term contracts in the near to medium term, we expect that some mechanism will be necessary to motivate and incentivize investment in the new priority area of energy storage. In this regard, we anticipate that amendments to market rules will be studied and introduced to encourage investment in additional energy storage facilities by ensuring that market-based price signals take into account the full value that the flexibility of such projects can bring to the system.

We expect that a major area of focus for 2018 and onward will be IESO enforcement and compliance. The Auditor General of Ontario's 2017 Report (the AG Report) found that the IESO has been under-performing in the area of compliance and market rule changes to prevent gaming behaviour. It specifically noted that that the Market Assessment and Compliance Division (MACD), which is responsible for market rule enforcement has been understaffed.[8]

In response to the AG Report, the IESO agreed that MACD had been understaffed in the past and pointed to current and planned staff increases at MACD, in particular, staff with investigation expertise.[9]

Given the media profile of the AG Report, we expect that market rule enforcement will be a strategic priority for the IESO in 2018 and beyond.

Another area of focus for 2018 will be regulatory reform at the OEB, particularly in the area of technological innovation. Both the Minister of Energy and the OEB have launched initiatives to address, among other things, how the OEB can facilitate the use of innovative technologies, such as smart grid and storage through changes

[8] p.331.
[9] p. 359.

to OEB processes and rate design.[10] One of the major areas of review will be the ability of local distribution companies to invest in “non-wires” solutions and recover the costs of these investments by rate payers. The OEB and the Minister may have different positions on this issue and it will be interesting to see how these dual, and perhaps competing initiatives will play out in 2018.

[10] See: Ontario Establishing Panel to Modernize the Ontario Energy Board, December 15, 2017 and the OEB’s Strategic Blueprint: Keeping Pace with an Evolving Energy Sector. December 18, 2017.

Québec

Mathieu Leblanc

Matthieu Rheault

Louis-Nicolas Boulanger

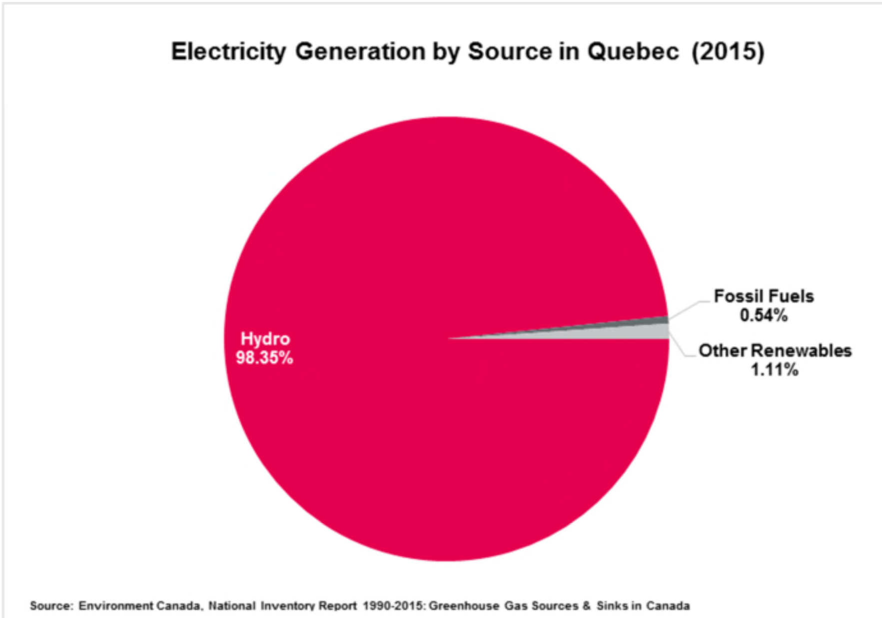
Martin Thiboutot

Introduction

2017 can again be characterized as a year of transition for the Québec energy sector. In 2016, the Québec Government announced its energy plans for the next 15 years and stated its ambitious goal of becoming a North American leader in renewable energy and energy efficiency by 2030. However, industry observers publicly indicated that they thought this energy policy fell short of establishing a clear action plan for the procurement of additional renewable energy in Québec. Such criticism may change in the not-too-distant future as Québec reduces its electricity surpluses and reinforces its desire to become a leader in clean energy. Optimistic industry participants predict that such circumstances may result in independent power producers (IPPs) participating in investment opportunities in Québec in the near future. In that sense, the initiative announced by the Québec Government in June 2017 that Hydro-Québec will develop a pilot solar energy park constitutes an interest development.

As demonstrated with the recent request for proposals for the development of a 6 MW wind farm in the Îles-de-la-Madeleine and the development of a biomass cogeneration project in Obedjiwan, we expect that Hydro-Québec will seek the participation of the private sector to develop and implement clean energy alternatives to replace fossil fuel in remote and off-grid areas where connection to the main grid would be prohibitive from a cost perspective.

Also in 2017, a number of Québec-based renewable energy projects were submitted in response to the request for proposals to supply renewable energy to the New England market. The long-awaited changes to the current legal framework for electricity export from Québec, expected in 2018, should advance these opportunities. Changes to the legal framework are expected to be introduced by new regulations in the spring of 2018.



QUÉBEC ENERGY POLICY: 2017-2020 ACTION PLAN

On June 26, 2017, Québec's Energy and Natural Resources Minister, Mr. Pierre Arcand, unveiled the 2017-2020 Action Plan (the Plan), a first step towards implementing the 2030 Energy Policy made public in April 2016 by the Québec Government.

The Plan sets out 42 measures, backed by $1.5 billion in public funding, providing for concrete actions which are divided in four streams: (1) integrating the transition governance; (2) fostering transition towards a low carbon footprint economy; (3) offering consumers a diversified and renewable energy supply; and (4) defining a new approach with respect to fossil fuels. While much remains to be confirmed, the Plan as presented should appeal to the energy industry by creating investment opportunities in Québec, without neglecting environmental targets.

The Plan emphasizes Hydro-Québec's role as Québec's leading electricity producer. Under the Plan, Hydro-Québec is instructed to develop, as a pilot project, a solar energy park as soon as 2017. An additional 1,140 MW of hydro power will be procured by updating older power plants. Hydro-Québec's "Rate L" will also be revised to encourage more private investment from large industries. To increase Hydro-Québec's profits, additional long-term export agreements are expected to be signed, while the legal framework for privately exporting wind power will be revised. A new regulation for that purpose should be published in the spring of 2018.

Several industry sectors will be impacted by the Plan. In particular, trucking companies will be entitled to receive grants if they reduce the fuel consumption of their fleet, while transportation and mining companies will be eligible for funding to convert vehicles to electricity, natural gas or propane.

Also noteworthy is the requirement that by 2020 gasoline sold in Québec must be comprised of at least 5% biofuel (2% for diesel) and that the natural gas distributed in the Province must include 5% "renewable" gas, which the Plan will support through investment in biogas (biomethanization) plants.

SUBMISSION OF QUÉBEC PROJECTS INTO MASSACHUSETTS CLEAN ENERGY RFP

In the summer of 2017, five Massachusetts-based affiliates of electricity distributors Unitil, Eversource and National Grid, together with the Massachusetts Department of Energy Resources, reported receiving 46 proposals submitted in response to Massachusetts' Request for Proposals for Long-term Contracts for Clean Energy Projects (the Massachusetts RFP) issued in March 2017. Québec-based renewable energy projects feature prominently among the proposals submitted, possibly as a result of Québec's announced plan to revisit the legal framework for privately exporting wind power from the province, as noted above.

The Massachusetts RFP is one of several initiatives put forward to meet Massachusetts' ambitious clean energy goals, most recently promoted by its enactment of the Chapter 188 energy diversity bill in 2016 (the Bill). Among other matters, the Bill mandates that Massachusetts distributors enter into long-term contracts for the annual procurement of approximately 9,450,000 megawatt-hours (MWh) of renewable energy from wind, solar, hydro or energy storage sources.

In total, Hydro-Québec is involved in six proposals. These include all hydro power (1,000 MW and 700 MW) and hydro and wind power supply blends, over three proposed new transmission lines, including joint proposals with Energir, L.P. (formerly Gaz Metro Limited Partnership) and Boralex Inc. in connection with both the New England Clean Energy Connect 1,200 MW transmission line and the Northern Pass 1,090 MW transmission line, and with TDI New England (an affiliate of Blackstone Group LP) in connection with the New England Clean Power Link 1,000 MW transmission line. Boralex and Energir's new wind power project would be located on the Seigneurie de Beaupré lands in Québec.

EDF Renewable Energy, Inc. submitted two proposals, with wind power projects totalling 804 MW and a 1,200 MW GridAmerica transmission line from Québec.

Renewable Energy Systems Canada Inc. submitted two proposals, with wind power projects totalling 500.4 MW and a 1,200 MW GridAmerica transmission line from Québec. The two new wind power projects would be located in Northern and Southern Québec, respectively.

Results of the selection process are due to be announced on January 25, 2018 and successful bidders are expected to negotiate and enter into 20 year-long supply or transmission contracts with the various Massachusetts distributors by March 27, 2018.

It remains to be seen how much the proposed changes to the legal framework for privately exporting wind power from Québec will do to facilitate the process, but the development of renewable energy projects for the purpose of exporting electricity into the New England market may become a growing trend in the near future.

OPENING OF SUBMISSIONS FOR THE HYDRO- QUÉBEC 6 MW WIND REQUEST FOR PROPOSALS

On October 12, 2017, Hydro-Québec Distribution (HQD) proceeded with the public opening of submissions received in response to its request for proposals (A/P 2015-01) (RFP) for the development, construction and operation of a 6 MW wind farm in the Îles-de-la-Madeleine, in Québec. A total of three submissions from TUGLIQ Energy, Kruger Energy and Valeco have been received by HQD for wind power projects with guaranteed commencement dates of delivery spanning between October 1 and December 31, 2019.

This RFP was initially issued on October 23, 2015. At the time, it was contemplated that the wind farm would be located on lands designated by the Régie intermunicipale de l'énergie Gaspésie-Îles-de-la-Madeleine (the Régie) and managed by the Îles-de-la-Madeleine municipality, at Dune-du-Nord. However, this site initially failed to meet some of the criteria set out by the Ministry of Sustainable Development, Environment and the Fight against Climate Change (the Ministry) concerning the protection of flower species and, in December 2015, HQD announced The relocation of the wind farm was considered for some time before the Ministry finally approved a revised approach for the implementation of the project at Dune-du-Nord.

Bidders were required to submit with their submissions a resolution of the Régie supporting their projects, and the selected bidder will have to enter into a partnership agreement with the Régie before execution of the power purchase agreement with HQD. The announcement of the winning bidder is scheduled for the first quarter of 2018.

TOPICAL ANALYSES

Environmental Law

Selina Lee-Andersen

Kimberly Howard

Dominique Amyot-Bilodeau

Joanna Rosengarten

Key Developments in 2017

In 2017, there were a number of key environmental law developments across Canada with potential impacts on the energy sector. Highlights include the following:

BRITISH COLUMBIA

New NDP Government Ushers in a New Environmental Policy Era

In July 2017, the provincial New Democratic Party (NDP) came into power. Under the new Environment Minister, George Heyman, the Ministry of Environment became the Ministry of Environment and Climate Change Strategy. In the Premier's mandate letter to Minister Heyman dated July 18, 2017, several policy priorities were established for Minister Heyman and his department, including: (1) renewal of the Climate Leadership Team within the first 100 days of his mandate; (2) implementing a comprehensive climate action strategy that provides a pathway for the Province to prosper economically, including setting a new legislated 2030 reduction target and establishing separate sectoral reduction targets and plans; (3) working with the Minister of Finance to implement an increase of the carbon tax by $5 per tonne of carbon dioxide equivalent (CO2e) beginning April 1, 2018 to meet the Federal Government's carbon pricing mandate and taking measures to expand the carbon tax to fugitive emissions and slash-pile burning; (4) revitalizing the environmental assessment process; (5) employing every tool available to defend the Province's interests in the face of the expansion of the Kinder Morgan pipeline; and (6) enacting an endangered species law.

Carbon Tax to Increase in April 2018

In its first provincial budget released on September 11, 2017, the NDP announced changes to the BC carbon tax. In particular, the Budget 2017 Update (2017/18 – 2019/20) provides that as of April 1, 2018, the carbon tax will increase by $5 per tonne of CO_2e per year until it reaches the federal target carbon price of $50 on April 1, 2021 (one year before Ottawa's 2022 deadline). BC's carbon tax is currently set at $30 per tonne of CO_2e. In addition, Part 2 of the *Carbon Tax Act* has been repealed, meaning that the requirement for the Minister of Finance to prepare the Carbon Tax Report and Plan will no longer apply after September 11, 2017. This also means that the *Carbon Tax Act* will no longer require that revenue measures be introduced to offset carbon tax revenues, paving the way for the BC government to spend carbon tax revenues on emission reduction measures or other green initiatives, rather than returning carbon tax revenues to taxpayers.

New Climate Change Advisory Panel Appointed

On October 23, 2017, the NDP appointed a new 22-member advisory council that will provide strategic advice to government on areas of focus for climate action that facilitate economic growth. The Climate Solutions and Clean Growth Advisory Council's work will inform a new climate strategy for BC. In particular, the advisory council (which consists of members from First Nations, environmental organizations, industry, academic researchers, labour and local government) has been tasked with working with industry and the Federal Government to address the competitiveness of emissions intensive, trade-exposed sectors. The advisory panel will meet quarterly.

Amendments to *Contaminated Sites Regulation* Come into Force

In October 2016, the Stage 10 (Omnibus) Amendments to the *Contaminated Sites Regulation* (CSR) under the *Environmental Management Act* were approved. These changes, which represent the most significant update to the CSR since its inception in 1997, came into effect on November 1, 2017. These amendments update all existing soil, water and vapour standards to reflect contemporary science, while consolidating existing schedules into four new schedules organized by environmental media: soil, water, vapour and sediment. The Stage 11 (Housekeeping) Amendments to the CSR were approved on October 31, 2017, which corrected certain errors in the Stage 10 amendments.

New Spill Response Regulations now in Force

On October 30, 2017, three new spill response regulations came into force, which establish new preparedness, response and recovery requirements aimed at the transportation of liquid petroleum products. These regulations include the *Spill Preparedness, Response and Recovery Regulation*; the *Spill Reporting Regulation* and the *Spill Contingency Planning Regulation*. Regulated persons have been identified as transporters of liquid petroleum products. The owners of Ministry regulated pipelines transporting any amount of liquid petroleum products are regulated persons, as are the owners of rail and highway transporters in possession of 10,000 liters or more. To demonstrate preparedness, regulated persons are required to develop and test provincial spill contingency plans. In terms of spill response, responsible persons will be required to meet enhanced spill reporting requirements, carry out all the response actions specified in the legislation as well as any additional steps required by a director and, if directed to do so, develop and implement a recovery plan that addresses any damage done to the environment. A responsible person is someone who has possession, charge or control of a substance or thing when a spill of the substance or thing occurs or is at imminent risk of occurring. Most new spill reporting requirements will not come into force until October 30, 2018.

ALBERTA

New Directives for Wind and Solar Energy Projects

In January 2017, Alberta Environment and Parks (AEP) issued an updated *Wildlife Directive for Alberta Wind Energy Projects.* The directive, which updates the *2011 Wildlife Guideline for Alberta Wind Energy Projects,* sets out potential wildlife issues associated with wind energy projects and provides standards and best management practices for minimizing impacts to wildlife and wildlife habitat during the siting, construction and operation of wind farms in Alberta. AEP has also developed the following supporting documents: (a) Renewable Energy External Wind: Checklist A – Standard Approach; (b) Renewable Energy External Wind: Checklist B – Buildable Area Approach; and (c) Grandfathering Administrative Procedure: Wind Energy Review Process (which outlines the transition process from the 2011 wildlife guideline to the 2017 wildlife directive). The *Wildlife Guidelines for Alberta Solar Energy Projects* is currently in interim form and provides similar wildlife guidelines for solar energy projects in Alberta.

Amendments to the *Environmental Protection and Enhancement Act*

In addition to introducing the new Renewable Electricity Program (REP) administered by the Alberta Electric System Operator (AESO), the *Renewable Electricity Act*, proclaimed in force on March 1, 2017, amended Alberta's *Environmental Protection and Enhancement Act* (EPEA) to add wind and solar power generation to EPEA's Schedule of Activities. Without additional regulations, a formal AEP approval, registration or notice under EPEA is still not required for the operation of wind or solar generation facilities. However, there are a number of impacts from this amendment:

- operators now have a statutory duty to reclaim wind and solar generation projects if the activities take place on "specified land" within the statutory definition. This includes the obligation to obtain a remediation certificate. Specified land is defined in the EPEA as land upon which an "activity" has been carried on, excluding lands solely used for agricultural purposes or residential purposes and Crown lands. By adding solar and wind power generation to EPEA's Schedule of Activities, the project lands fall within the definition of "specified land" because the activity of a solar or wind generation facility is being conducted thereon. As a result, as part of decommissioning, solar and wind generation operators will have a duty to reclaim the specified lands and obtain a reclamation certificate pursuant to the Conservation and Reclamation Regulations enacted under the EPEA;
- AEP can issue environmental protection orders, mandating that solar and wind generation projects operators (and potentially their directors and officers) complete the requisite conservation and reclamation work; and
- wind and solar generation projects can now, subject to a Ministerial Order, be designated as activities requiring security be posted to the Minister to cover, among other things, end of life reclamation obligations.

Implementation of the Climate Plan

Near the end of 2015, Alberta released its Climate Leadership Plan (Climate Plan) which, among other things, promises an economy-wide carbon price, a legislated cap on oil sands emissions and sets goals for the phase-out of coal-fired generation by 2030. For the power sector, the objective is to replace two-thirds of the existing coal electricity with renewable energy and one-third with natural gas. The 2030 goal is for renewable sources to account for 30% of Alberta's total operating generation capacity. For more information on the Climate Plan, please refer to the Alberta section of this publication.

Province-wide Carbon Levy

As of January 1, 2018, a $30 per tonne carbon levy was applied to fuels that emit greenhouse gas when combusted. Fuels covered by the levy include transportation and heating fuels such as diesel, gasoline, natural gas and propane. It will not apply directly to consumer purchases of electricity. Revenues from the carbon levy will be used for initiatives to reduce greenhouse gas emissions and to fund carbon rebates, as well as for investments in clean technology and green infrastructure. The carbon levy will also be used for an "adjustment fund" to help individuals and families, small business and First Nations adjust as the new policy is implemented.

Legislated Cap on Oil Sands Emissions

On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force legislating the 100 megatonne (MT) per year greenhouse gas emission cap from oil sands production. This legislation contemplates certain exceptions in respect of cogeneration emissions, upgrading emissions and potential discretionary exemptions by regulation (likely to accommodate new technological developments). On June 16, 2017, the Alberta Oil Sands Advisory Group (OSAG) released its report *Recommendations on Implementation of the Oil Sands Emissions Limit Established by the Alberta Climate Leadership Plan.* The report sets out recommendations on early actions designed to encourage additional emissions reductions, as well as additional actions in the event that emissions begin to approach the 100 MT emissions limit. These actions are intended to work in concert with the output-based allocation system for carbon pricing and to encourage greenhouse gas efficiency so that the aggregate emissions remain under the limit without limiting production.

Methane Emissions Reduction Plan

Alberta intends to cut methane emissions by 45% from 2014 levels by 2025.The Province's largest source of methane emissions is from the oil and gas industry (venting, fugitive emissions from leaks and natural gas driven pneumatics and from flaring). The former Climate Change and Emissions Management Corporation, now Emissions Reduction Alberta, has earmarked a total of $40 million to help advance technologies to reduce methane emissions in Alberta, providing successful applicants with up to a maximum of $5 million. Under the direction of Alberta Energy, the Methane Reduction Oversight Committee was formed in September 2016 and consists of members from government, environmental non-government organizations, industry and technology groups. Alberta's reduction target and timeline match the commitments recently announced by the Federal Government pursuant to its two proposed regulations: *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*, and *Regulations Respecting Reduction in the Release of Volatile Organic Compounds (Petroleum Sector).* Alberta's target to release the draft methane reduction regulations was the fall of 2017. However, in mid-November 2017, it was announced that the release of the draft regulations would be delayed and the Methane Reduction Oversight Committee's discussions extended.

ONTARIO

Cap-and-Trade Program

Ontario's cap-and-trade program came into force on January 1, 2017 and is governed by the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* as well as the *Cap and Trade Regulation* (O. Reg. 144/16) and other regulations. Quarterly auctions for allowances were held on March 22, 2017, June 6, 2017, September 6, 2017 and November 29, 2017. The results of the auctions were as follows:

- March 22, 2017: All current 2017 vintage allowances sold (at a settlement price of $18.08 per allowance) and ~25% of future 2020 vintage allowances sold (at a settlement price of $18.07 per allowance) ($472,031,155 in proceeds);
- June 6, 2017: All current 2017 vintage allowances sold (at a settlement price of $18.72 per allowance) and ~50% of future 2020 vintage allowances sold (at a settlement price of $18.30 per allowance) ($504,182,190 in proceeds);

- September 6, 2017: all current vintage allowances sold (at a settlement price of $18.56 per allowance) and all of future 2020 vintage allowances sold (at a settlement price of $18.03 per allowance) ($525,694,672 in proceeds); and
- November 29, 2017: 83% of current vintage allowances sold (at a settlement price of $17.38 per allowance) and all future 2020 vintage allowances sold (at a settlement price of $18.89 per allowance) ($422,081,073 in proceeds).

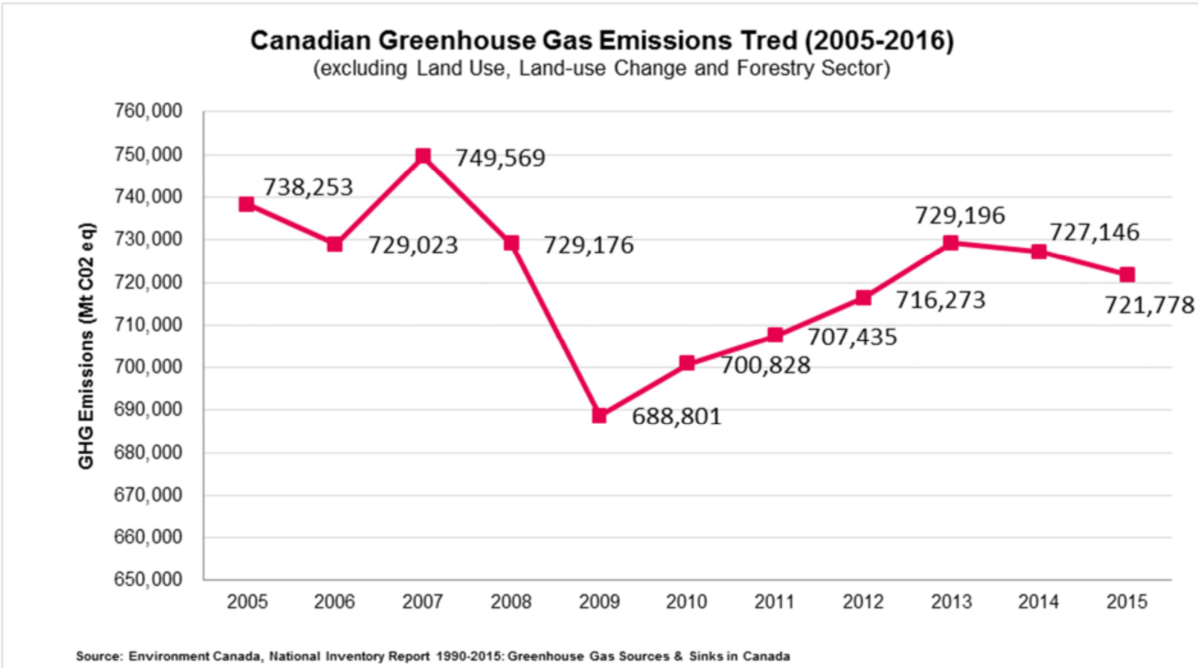
The cumulative proceeds from the four auctions was close to $2 billion and was directed to the Ontario Greenhouse Gas Reduction Account (GGRA). The funds from the GGRA will be used to invest in programs aimed at reducing greenhouse gas emissions, such as improving cycling infrastructure, making buildings more energy efficient, creating a network of fast-charging electric vehicle stations across the Province, helping to fund the purchase of electric school buses, helping businesses adopt leading technologies to reduce greenhouse gas emissions and helping First Nations communities to reduce reliance on diesel fuel.

Compliance Offsets Program under Cap-and-Trade

In addition to purchasing allowances at auctions, government sales and private sales, under the Ontario cap-and-trade program, participants are able to meet up to 8% of their compliance obligations through the purchase of offset credits. In October 2017, the government released for comment: (1) a draft offset regulation that would enable the creation of offset credits for use in Ontario's cap-and-trade program; and (2) a draft protocol – the Landfill Gas protocol - to be incorporated into the regulation. This protocol will enable the collection and destruction of methane collected from landfill gas, and the creation of offset credits based on the consequent reduction of greenhouse gas emissions. Future protocols for the creation of offset credits will also be posted for public comment. In 2018, Ontario will likely see the finalization of the offset regulation and the landfill gas protocol, as well as the introduction of new protocols. Participants in Ontario's cap-and-trade program will be able to begin purchasing offset credits to meet up to 8% of their compliance obligations.

Voluntary Carbon Offsets Program

Ontario is developing a voluntary carbon offsets program for use by individuals, organizations and companies who want to voluntarily reduce their greenhouse gas emissions. The program will establish a clear set of rules and requirements for anyone who wants to create carbon offsets projects that generate carbon credits that may be traded on the voluntary market. The proposed voluntary carbon offsets program is separate and distinct from the proposed compliance offsets program and capped emitters will not be able to use voluntary carbon offset credits to meet their compliance obligations under the cap-and-trade program. In November 2017, the Ontario Government posted a discussion paper on key elements of a proposed voluntary carbon offsets program to the Environmental Registry for a 46-day consultation period, which ran until January 15, 2018.



QUÉBEC

Modernization of *Environment Quality Act*

On March 23, 2017, the Québec National Assembly passed Bill 102 in order to modernize the environmental authorization scheme under the Québec *Environment Quality Act*. Among other things, Bill 102 modifies the environmental impact assessment and review process (the EIA process) for major projects and allows the Government to subject any project to the EIA process if, in its opinion the project: (i) may raise major environmental issues and public concern warrants it; (ii) involves a new technology or new type of activity in Québec whose apprehended impacts on the environment are major; or (iii) involves major climate change issues. Bill 102 facilitates public access to various environmental and permitting documents filed by proponents with the Québec Ministry of Environment (MDDELCC). Many provisions of this Bill will come into force in March 2018, further to the adoption of the underlying regulatory regime.

New Wetlands Conservation Framework

On June 16, 2017, the Québec National Assembly adopted Bill 132, an *Act respecting the conservation of wetlands and bodies of water*. This omnibus bill reforms the legal framework applicable to wetlands and bodies of water (WBW) in the Province to increase their conservation and enshrines the principle of "no net loss" of WBW. Bill 132 introduces a definition of WBW broader than that applied in the past. In practice, this will increase the number of lands where WBW are deemed present and trigger the challenging authorization process. Bill 132 requires proponents to demonstrate to the satisfaction of the Ministry that there is no other space available for the purposes of the project and that the project has been designed to minimize impacts on WBW. If a proponent is able to convince the MDDELCC that destruction of WBW should be authorized, a significant monetary compensation will have to be paid by the proponent to the Government to finance WBW restoration and conservation projects.

FEDERAL

Federal Government Completes Review of Environmental and Regulatory Processes

On June 20, 2016, the Federal Government launched a comprehensive review of four key environmental and regulatory processes under the *Canadian Environmental Assessment Act, 2012*, *National Energy Board Act, Fisheries Act*, and *Navigation Protection Act*.

In spring 2017, the expert panels tasked with reviewing these processes issued their final reports. On June 29, 2017, the Federal Government released a discussion paper which outlines potential reforms being considered to rebuild confidence and to modernize Canada's environmental and regulatory processes. Key measures include:

- establishing a single government agency responsible for assessments of federally designated projects. The review would go beyond environmental impacts to also consider social, health and economic aspects of a project and require a gender-based analysis. Joint assessments will be undertaken with the life cycle regulator for major energy transmission, nuclear and offshore oil and gas projects;
- requiring an early planning phase to foster greater collaboration and engagement between proponents, Indigenous peoples, stakeholders, the public and the Federal and Provincial Governments;
- early and regular engagement and partnership with Indigenous peoples based on recognition of Indigenous rights and interests from the outset, seeking to achieve free, prior and informed consent through processes based on mutual respect and dialogue; and
- restoring lost protections and incorporating modern safeguards to the *Fisheries Act* and the *Navigation Protection Act*.

The public comment period on the discussion paper closed on August 28, 2017. The Federal Government has indicated that this discussion will inform proposed changes to Canada's environmental assessment and regulatory processes in 2018.

The Year Ahead

BRITISH COLUMBIA

Second Phase of *Water Sustainability Act*

The *Water Sustainability Act* (WSA) came into effect on February 29, 2016. The first implementation phase involved the development of policies and regulations associated with groundwater use, stream protection, and water use in the mining sector. The Province has yet to establish and implement the second phase of the WSA, which includes water objectives, water sustainability plans, measuring and reporting requirements, livestock watering, designating areas, dedicated agricultural water and alternative governance approaches. For the purposes of sustaining water quantity, water quality and aquatic ecosystems, water objectives may be set by regulation in relation to watersheds, streams or aquifers. These objectives will likely form the basis for decision makers in the determination of water allocation and water licence conditions.

Continued Implementation of Spill Reporting Regime

As noted above, most new spill reporting requirements will not come into force until October 30, 2018. Certain provisions of the spill preparedness, response and recovery division of the EMA are not yet in force and will require individual regulations. Additional provisions will be brought into force over the next two to three years during later phases of regulatory development. In early 2018, the BC Ministry of Environment and Climate Change Strategy (the Ministry) will engage with interested parties regarding further enhancements to spill regulations.

Shifting Environmental Policy Priorities

As set out in the Minister's mandate letter, the NDP Government has identified certain priority policy areas, including climate change, environmental assessments, and endangered species. Over the next year, we expect the Ministry to further articulate its policy priorities and undertake activities to achieve those priorities.

ONTARIO

Further Evolution of Ontario's Cap-and-Trade Program

As noted above, Ontario will likely see the finalization of the offset regulation and the landfill gas protocol in 2018, as well as the introduction of new protocols. Participants in Ontario's cap-and-trade program will be able to begin purchasing offset credits to meet up to 8% of their compliance obligations. This year will also see the linking of the Ontario cap-and-trade program with the Québec and California programs. The Ontario Government has amended Ontario's legislation in order to link the programs as of January 1, 2018. Joint allowance auctions will be held by the three jurisdictions and participants will be able to trade allowances between jurisdictions.

QUÉBEC

Modernization of *Environment Quality Act*

The MDDELCC has announced multiple amendments to existing regulations that will be published in 2018 in order to give effect to Bill 102, which was adopted on March 23, 2017 to modernize the Québec environmental permitting regime. These amendments could potentially have a significant impact on major energy projects in the Province.

New Wetlands Conservation Framework

The MDDELCC has announced that new regulations will be adopted in 2018 to give effect to the new *Act respecting the conservation of wetlands and bodies of water*. These amendments will, among other things, specify which floodplains will be protected by the new large framework applicable to WBW and which interventions are not subject to the rigorous new permitting regime established under Bill 132. New regulations will also be adopted to confirm the amount of the financial compensation that proponents must pay for projects that have adverse effects on WBW.

FEDERAL

Proposed Changes to Legislation Expected Following Review of Environmental and Regulatory Processes

As discussed above, the Federal Government completed its review of environmental and regulatory processes in spring 2017. The Federal Government has indicated that feedback received during public consultations on the June 2017 discussion paper will inform proposed changes to Canada's environmental assessment and regulatory processes in 2018.

Federal Carbon Pricing Backstop to Come into Force in 2018

The Federal Government will continue to implement the *Pan-Canadian Framework on Clean Growth and Climate Change* (the Framework), including the implementation of a carbon pricing backstop to ensure that Provinces and Territories establish a minimum price of $10 per tonne of CO_2e starting in 2018, which will increase by $10 per year until it reaches $50 per tonne of CO_2e by 2022. Under the Framework, each Province and Territory is required to implement carbon pricing in its jurisdiction within two years, whether in the form of a carbon tax or a cap-and-trade system. In October 2017, the Manitoba Government announced that it will implement a carbon price of $25 per tonne of CO_2e. With this announcement, Manitoba joins four other provinces that have already implemented carbon pricing systems (Ontario, Québec, Alberta and BC). Federal and Provincial Governments will deliver an interim progress report in 2020, while undertaking a more comprehensive review of the stringency and effectiveness of carbon pricing across Canada by early 2022, which will inform the path forward. In 2018, the Federal Government is expected to release draft regulations for the backstop mechanism and to issue a report on the competitiveness of emissions-intensive and trade-exposed sectors.

The following table illustrates projected carbon prices across the country:

PROVINCE	2018 ($)	2022 ($)	CARBON PRICE COMPLIANCE PROTOCOL
British Columbia	$ 35	$ 50	New BC Government to raise by $ 5/tonne each year
Alberta	$ 30	$ 50	Agreed to follow federal plan beginning in 2021
Saskatchewan	$ 10	$ 50	Imposed federal backstop presumed
Manitoba	$ 25	$ 25	Made-in-Manitoba Prairie Price
Ontario	$ 18	$ 22 floor price	Cap-and-Trade forecasted*
Québec	$ 18	$ 22 floor price	Cap-and-Trade forecasted*
New Brunswick	$ 10	$ 50	Agreed to following federal plan beginning in 2018
Nova Scotia	Under development		Federal equivalency for NS internal cap-and-trade plan
Prince Edward Island	$ 10	$ 50	Agreed to following federal plan beginning in 2018
Newfoundland	$ 10	$ 50	Agreed to following federal plan beginning in 2018

*Ontario Energy Board Long Term Carbon Price Forecast Report (2017)

Source: Government of Manitoba's A Made-in-Manitoba Climate and Green Plan report (2017)

Aboriginal Law

Selina Lee-Andersen | Bryn Gray | Stephanie Axmann | Daniel Goudge

Introduction

In 2017, there were a number of key Aboriginal law developments with potential impacts on the energy sector.

SUPREME COURT OF CANADA (SCC)

SCC dismissed an Aboriginal spiritual rights claim in *Ktunaxa Nation v. British Columbia (Forests, Lands and Natural Resource Operations)*, 2017 SCC 54

In *Ktunaxa*, the SCC dismissed a novel freedom of religion claim opposing the proposed Jumbo ski resort development in BC. It was the first time the SCC considered an Aboriginal spiritual rights claim seeking protection under section 2(a) of the *Canadian Charter of Rights and Freedoms* (the Charter), in conjunction with an alleged failure to fulfill the duty to consult. The Ktunaxa Nation sought to overturn the Province's approval of a master development agreement for the resort, arguing that any development would interfere with a sacred area known as Qat'muk, and in particular would drive the Grizzly Bear Spirit from Qat'muk. After nearly 20 years of resort planning and approvals, including significant consultation and accommodation, the Ktunaxa took a late position that no accommodation was possible.

The majority of the court held that the Ktunaxa's freedom of religion claim was not protected by section 2(a) of the *Charter*. The right to freedom of religion provides for the freedom to hold religious beliefs and to manifest those beliefs, but such rights were not infringed in this case. Rather, the Ktunaxa sought to protect the Grizzly Bear Spirit itself (the object of their spiritual belief), and their subjective spiritual fulfilment derived from it, both of which are not protected. In a minority decision (concurring in the result), Justice Moldaver opined that by driving the Grizzly Bear Spirit from Qat'muk, the approval decision did infringe section 2(a) because it would interfere with the Ktunaxa's ability to act in accordance with their religious belief in more than a trivial or insubstantial manner, rendering it devoid of all spiritual significance. However, he found that the decision was reasonable because it reflected a proportionate balancing of the religious right and the Minister's statutory objectives to administer Crown land in the public interest.

The SCC unanimously held that the Crown met its duty to consult with the Ktunaxa, and the Minister's conclusion in this regard was reasonable. Deep consultation was undertaken and was adequate, even though the Ktunaxa ultimately did not achieve their desired outcome. The SCC reiterated comments from past decisions stating that "the s. 35 obligation to consult and accommodate is a right to a process, not to a particular outcome" and "s. 35 does not give unsatisfied claimants a veto over development."

This decision restricts the types of Aboriginal spiritual rights claims that will engage s. 2(a) *Charter* protections. It suggests that broad Aboriginal spiritual rights claims over a land base are unlikely to be protected by freedom of religion. Even if an infringement of freedom of religion is found, it may not meet a proportionality test.

In two decisions concerning the National Energy Board, the SCC confirmed regulatory tribunals can act in place of the Crown and fulfill the duty to consult

In both decisions, the SCC confirmed that the Crown can rely in whole or in part on regulatory processes to fulfill the duty to consult, but that the Crown must take further measures to meet its duty to consult if the regulatory process being relied upon does not achieve adequate consultation or accommodation. The SCC also clarified that decisions of regulatory tribunals and agencies can constitute "Crown conduct" for the purposes of triggering the duty to consult if they are in effect acting on behalf of the Crown when making a final decision through delegated authority, even if they are not strictly speaking the "Crown" or an agent of the Crown at law. The SCC held that in both cases, where the Crown was absent and the National Energy Board (NEB) was the final decision maker, its approval process was the conduct that triggered the duty to consult – the NEB exercises executive power on behalf of the Crown and "is the vehicle through which the Crown acts", and has sufficient procedural and remedial powers to fulfill the duty to consult.

While both cases concerned NEB processes, the SCC reached very different conclusions regarding the adequacy of consultation for each decision on the particular facts. In *Hamlet of Clyde River, et al. v. Petroleum Geo-Services Inc. (PGS), et al.*, 2017 SCC 40, the SCC found that the duty to consult was not met and quashed the NEB approval for a seismic testing program in Nunavut. In that case, it was the deficiencies in the specific process deployed that resulted in inadequate consultation (including too much focus on environmental impacts instead of impacts on treaty rights), rather than the NEB regulatory structure as a whole.

In contrast, in *Chippewas of the Thames First Nation v. Enbridge Pipelines Inc., et al.,* 2017 SCC 41, the SCC concluded that there had been adequate consultation for a proposed pipeline reversal and capacity expansion project, and dismissed the First Nation's appeal. As in *Ktunaxa*, the SCC emphasized the principle that the duty to consult does not provide impacted Indigenous groups with a veto over development projects. These decisions make clear that the Canadian Constitution does not provide Indigenous groups with a unilateral right to determine whether a development project proceeds or not (except in limited circumstances where Aboriginal title is established – per *Tsilhqot'in*). Rather, the duty to consult affords Indigenous groups the right to have their interests heard, considered, and balanced against other legitimate public interests that are relevant to a particular project. As the SCC held in *Chippewas*, Indigenous groups "are not entitled to a one-sided process, but rather, a cooperative one with a view towards reconciliation", and "balance and compromise are inherent in that process."

The SCC's acceptance of the NEB process is timely given the Government of Canada's ongoing review of environmental and regulatory legislation, including the NEB Act. Although changes to the NEB process may help impose consultation outcomes, the above SCC decisions raise questions with respect to the extent and necessity of such changes as they pertain to the duty to consult.

The SCC addressed a modern treaty dispute in *First Nation of Nacho Nyak Dun,* 2017 SCC 58

On December 1, 2017, the SCC issued a decision concerning a contested land use planning decision of the Yukon Government under the Yukon Umbrella Final Agreement. The case is one of a select few by the SCC to substantively address modern treaties, and thus provides helpful commentary with respect to the principles governing the interpretation of modern treaties, the role of the courts in resolving modern treaty disputes, and the remedies available where the Government breaches its treaty obligations.

The SCC held that Yukon's extensive changes to a Final Recommended Plan for land use planning in the Peel Watershed did not respect the process set out in the Final Agreements with the appellant First Nations, and quashed Yukon's approval of the plan. Overturning the Yukon Court of Appeal's decision, the SCC sent the parties back to a second round of consultation, as opposed to an earlier round of consultation. The SCC found it would be inappropriate to afford Yukon a second chance at earlier consultation, noting that it had failed to diligently advance its interests and exercise its rights, and that it must bear the consequences of that failure.

Emphasizing that modern treaties are intended to renew the relationship between Indigenous peoples and the Crown to one of equal partnership, the SCC stated that in the context of resolving modern treaty disputes, courts should generally "leave space for the parties to govern together and work out their differences", and that "reconciliation often demands judicial forbearance" (para. 33). However, the SCC acknowledged that modern treaties enshrine constitutional rights that courts must safeguard, and that such judicial restraint "should not come at the expense of adequate scrutiny of Crown conduct to ensure constitutional compliance" (para. 44).

The Federal Government undertook several steps towards implementation of the *United Nations Declaration on the Rights of Indigenous Peoples*

In May 2016, the Federal Government announced its full support for the *United Nations Declaration on the Rights of Indigenous Peoples* (UNDRIP) "without qualification" and its intention to implement it. The Federal Government is currently still in the reviewing and consulting phase of implementation, and it appears this will be a long process over many years. Implementation will primarily happen through initiatives of the Working Group of Ministers of the Review of Laws and Policies and other collaborative initiatives such as the ongoing federal environmental and regulatory reviews.

To date, federal statements and actions continue to suggest that it will interpret the provisions of UNDRIP that require the "free, prior, and informed consent" (FPIC) of Aboriginal groups in a number of situations, including resource development, as an objective and not an absolute requirement. However, the Government's statements and actions to date suggest it intends to make legislative and policy changes that go beyond what is currently required by the duty to consult. This will likely lead to requirements for increased and more meaningful involvement from Indigenous groups in all phases of federal project reviews and monitoring. It will also likely result in heightened Federal Government scrutiny of consultation and accommodation and efforts by proponents to obtain consent.

In November 2017, the Federal Government announced that it would be supporting Bill C-262, a private member's bill relating to the implementation of UNDRIP which was introduced by an NDP Member of Parliament. It is a short bill which does the following:

- affirms UNDRIP as a universal international human rights instrument with application in Canadian law;
- requires the Federal Government to take all measures necessary to ensure that the laws of Canada are consistent with UNDRIP;
- requires the development of a national action plan to achieve the objectives of UNDRIP; and
- requires the Minister of Crown-Indigenous Relations to provide an annual report to Parliament on implementation of measures between 2017 and 2037.

As worded, this bill will not amend any existing laws and does not result in the provisions of UNDRIP, including FPIC, being adopted word-for-word into Canadian law. The use of the word “application” suggests it would be an interpretive tool – but this would only be to the extent it is consistent with the Constitution, which the courts have repeatedly confirmed does not provide Aboriginal groups a veto over resource development. The law also provides for flexibility in implementation requiring consistency not strict compliance.

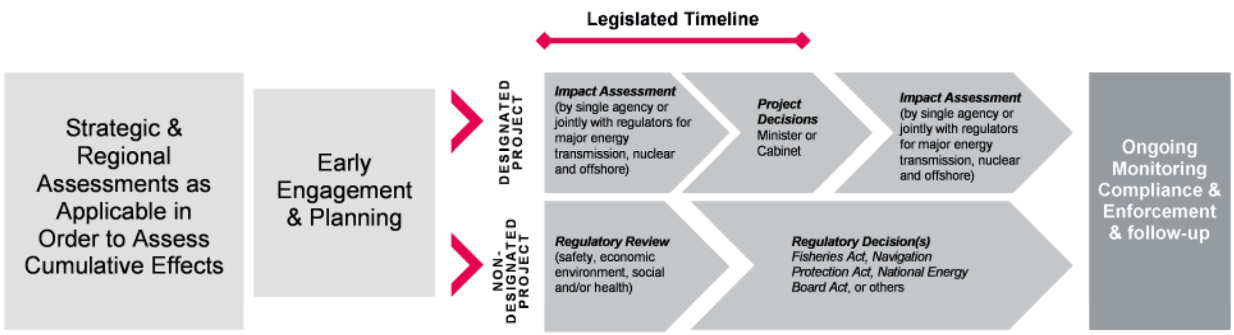
If passed, this law will likely result in greater public disclosure and scrutiny of the Federal Government’s efforts to implement UNDRIP. While provinces such as BC, Alberta and Ontario have indicated they intend to implement UNDRIP, each of these provinces have also made statements which suggest that the FPIC provisions are an objective of consultation and not an absolute requirement.

FEDERAL ENVIRONMENTAL AND REGULATORY REVIEWS UPDATE

In June 2016, the Federal Government announced four environmental and regulatory reviews to fulfill commitments that it made in its 2015 election platform. These four reviews have now been completed and the Federal Government is in the process of responding to four different reports with 136 recommendations, some of which are conflicting.

In June 2017, the Federal Government responded to these four reports through a discussion paper. Among other things, this discussion paper proposed changes with respect to the role of Indigenous peoples in project reviews, including:

- clarifying roles and responsibility for consultation and accommodation;
- introducing a new early planning and engagement phase led by proponents with direct Crown-Indigenous engagement aimed at seeking consensus on the project assessment process;
- increasing Indigenous participation and representation in project reviews through Indigenous participation/representation on project specific working tables, Ministerial Advisory Committees, and increasing Indigenous representation on assessment panels;
- allowing Indigenous led assessments/substitution with Indigenous governments;
- co-developing tools, guidance, and capacity with Indigenous peoples to better support and systematically consider Indigenous knowledge;
- increasing Indigenous capacity to participate in impact assessments and to participate economically in the projects; and
- collaborating on regional-scale studies and expanding the role of Indigenous peoples in post-approval monitoring.



Source: Government of Canada, Environmental and Regulatory Reviews Discussion Paper (June 2017)

The proposed changes suggest that the Federal Government is likely to introduce legislative, regulatory and policy amendments that will enhance the involvement of Indigenous groups in federally reviewed projects. It remains to be seen how these changes will be scaled out for linear projects, and whether such changes reduce or increase the number of disputes in project reviews.

These changes will likely be introduced through legislation in early 2018. Given the rushed process for the *Canadian Environmental Assessment Act 2012* (CEAA) introduced in omnibus legislation, there will likely be substantially more consultation through the legislative process before legislation is passed, which will be followed by further consultation on the development of regulations and policies.

SITE C PROJECT LITIGATION IN BRITISH COLUMBIA

Following the BC provincial election, the BC Government asked the BC Utilities Commission (BCUC) to review BC Hydro's Site C Project, a third dam and hydroelectric generating station under construction on the Peace River in northeast BC. The review began on August 9, 2017 and construction and procurement activities continued, although no major awards were made during the review period. The BCUC concluded that the project is over budget and is likely behind its scheduled completion date of 2024.[11] Nonetheless, on December 11, 2017, Premier John Horgan announced that the Province will proceed with completion of the project. He stated that it was a difficult decision, but that cancellation would result in adding billions to the Province's debt. In moving forward with the project, the Province will launch a "Site C turnaround plan to contain project costs while adding tangible benefits." In addition, however, the Premier advised that the Government will pursue an alternative energy strategy towards green renewable power to meet the Province's climate goals. The Premier acknowledged that Site C does not have the support of all Treaty 8 First Nations, but stated that "their voices were heard and their perspectives were an important part of the deliberations on a very challenging decision."[12]

Within the context of Site C litigation, several high-profile legal challenges against the Site C hydroelectric dam were resolved in late 2016 and early 2017. Two of these actions commenced with an application for judicial review of the Federal and Provincial Governments' decisions to issue environmental assessment certificates

[11] http://www.bcuc.com/Documents/NewsRelease/2017/11-01-2017_NewsRelease_Site-C-Final-Report.pdf
[12] https://news.gov.bc.ca/releases/2017PREM0135-002039

under their respective legislation. The Peace Valley Landowner Association's proceedings against the government concluded in September 2016 when the BC Court of Appeal affirmed the lower court's ruling that the decision by the Minister of the Environment was reasonable. Similarly, West Moberly and Prophet River First Nations were unsuccessful in their claims, at both the Federal Court of Appeal in January 2017 (2017 FCA 15), and at the BC Court of Appeal a month later (2017 BCCA 58). Both the West Moberly and Prophet River First Nations sought leave to appeal the Federal Court of Appeal decision to the Supreme Court of Canada, but on June 29, 2017, the Supreme Court of Canada issued a decision declining to hear the two appeals and dismissed the applications with costs.

Site C has not yet cleared its final legal hurdles. There is currently a challenge underway at the BC Environmental Appeal Board (2016-WAT-002(a), 003(a) and 004(a)), which has been brought by the West Moberly and Prophet River First Nations, as well as a landowner, to appeal the decision by the Deputy Comptroller of Water Rights to issue two water licences to BC Hydro. In addition, following the Premier's December 11th announcement, the Chiefs of West Moberly and Prophet River First Nations announced that they would be filing an injunction application to stop project construction, and to commence a civil action for Treaty 8 infringement.[13] Meanwhile, five other First Nations have entered into benefits agreements with BC Hydro in respect of the project.

BLUEBERRY RIVER FIRST NATIONS

These actions will benefit from the BC Supreme Court's decision in *Blueberry River First Nations v. British Columbia (Natural Gas Development), 2017 BCSC 540*, in which the court further considered the test for the duty to consult in the context of large-scale development projects. In Blueberry River, the Blueberry River First Nations (the BRFN) sought judicial review of a long-term royalty agreement entered into by the British Columbia Minister of Natural Gas Development and Progress Energy Canada Ltd., setting the royalty rates payable to the Province for the supply of natural gas to the Pacific North West LNG facility. The BRFN alleged that BC's decision to enter the agreement adversely impacted treaty rights – in particular, their hunting, trapping and fishing rights.

The parties agreed that the Province did not consult with the BRFN prior to entering the agreement. As a result, the dispute centered on whether the Province's decision triggered the duty to consult in the first instance. The court found that BC's decision to enter into the agreement did not trigger the duty to consult with the BRFN, finding that the BRFN had not established that there was a causal relationship between the decision under review and any adverse impact on their treaty rights. The court found instead that the adverse impact claimed by the BRFN was speculative, and thus did not give rise to the duty to consult. Notably, the court clarified that speculative claims do not give rise to the duty to consult as such claims inhibit the proper assessment of the scope of consultation required by the Crown's duty. The court stated, "without a clear understanding of the actual, appreciable impacts on a First Nation's rights, it is not possible to engage in meaningful consultation or develop appropriate accommodations."

This finding is particularly relevant in the context of large-scale development projects, where claims for breach of the duty to consult are often brought in relation to minor decisions on the project in order to object to the

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[13] https://www.sagelegal.ca/news-blog-1/2017/12/11/press-release-west-moberly-and-prophet-river-first-nations-to-seek-injunction-launch-site-c-infringement-action

cumulative impact of the project as a whole. The court's finding in *Blueberry River* clarifies that, in most cases, such decisions will not trigger the duty to consult; rather, the duty to consult will only arise where a decision has a direct causal impact on the rights of a First Nation.

The Year Ahead

MIKISEW CREE TO TAKE CHALLENGE TO 2012 OMNIBUS BILLS TO THE SCC IN JANUARY – SCC TO CONSIDER WHETHER THE DUTY TO CONSULT CAN BE IMPOSED ON THE LEGISLATIVE PROCESS

The SCC is scheduled to hear the Mikisew Cree's appeal from *Courtoreille v. Canada*, 2016 FCA 311 on January 15, 2018. *Courtoreille* concerns the Mikisew Cree's challenge to the previous Federal Government's introduction of omnibus bills amending Canada's environmental assessment regime under CEAA, as well as related environmental and regulatory approval legislation. The Mikisew Cree were not consulted on the amendments. They argued that the changes to such legislation could negatively impact their treaty rights to hunt, fish and trap, thereby triggering the duty to consult in respect of such legislation before it was passed into law.

Courtoreille will provide the SCC with an opportunity to address the lingering questions of whether and to what extent the Crown is obliged to consult with Aboriginal peoples in respect of proposed legislation that may affect Aboriginal and treaty rights – which it left "to another day" in *Rio Tinto Alcan v. Carrier Sekani Tribal Council*, 2010 SCC 43. In determining whether a duty to consult is owed during the legislative process, the appeal decision should address the separation of powers between the executive and the judiciary; specifically, whether courts have the power to judicially review and impose a duty to consult on the executive powers of Parliament, or whether courts are precluded from doing so because of the separation of powers. It may also address the notion put forth in the Federal Court of Appeal's minority decision of whether the duty to consult might arise in respect of legislation that directly affects First Nations, but not in respect of legislation of general application. If the SCC finds that the duty to consult can arise in particular circumstances, the further question will be at what stage in the legislative process might it arise (for example, whether on introduction into Parliament), and what might constitute sufficient consultation, and where appropriate, accommodation.

The issues to be decided in this case are timely in the context of the Federal Government's current task of reviewing the same environmental and regulatory legislation at issue. This case is also of relevance considering that in 2017 the Federal Government announced plans for a Ministers' Working Group to undertake a review of all federal laws and policies that affect Indigenous peoples' rights, to ensure the government is meeting its constitutional obligations to Indigenous peoples. The Federal Government has committed to consulting with Indigenous groups in respect of these reviews as a matter of good policy. *Courtoreille* will help to answer whether, and to what extent, government has a constitutional obligation to do so.

Mergers & Acquisitions

Cameron Hughes

Sven Milelli

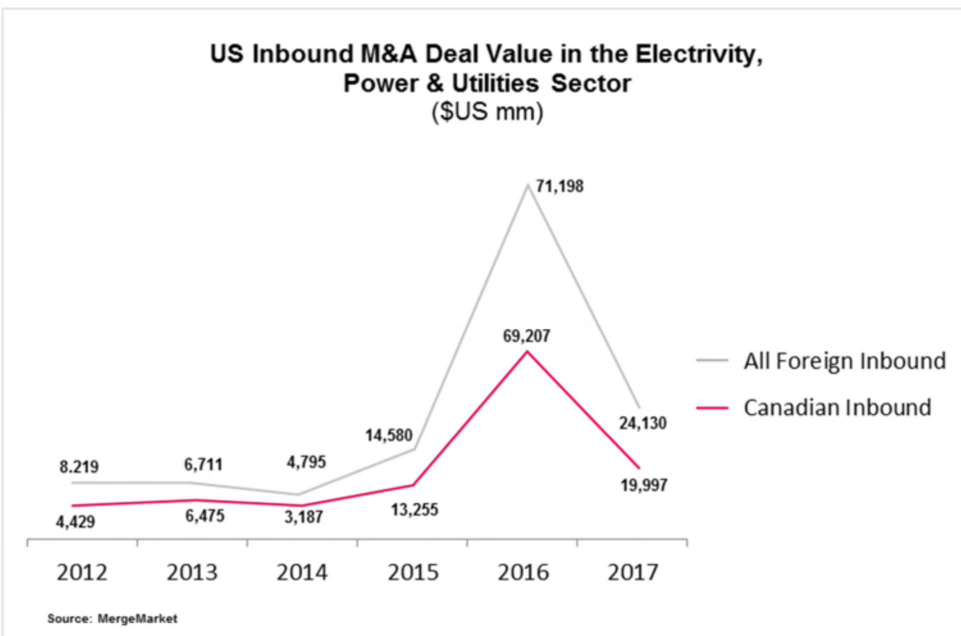
Seán C. O'Neill

Louis-Nicolas Boulanger

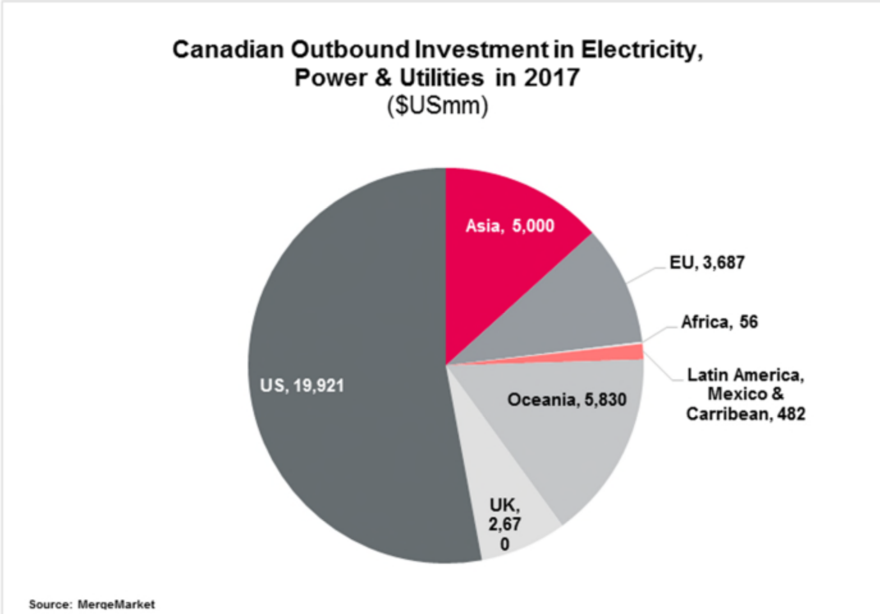
Scott Bergen

Introduction

2017 saw the continuation of two trends that emerged in M&A activity in the Canadian power sector in 2016 – an increased focus domestically on the acquisition of operating and yield-producing assets, and an uptick in investment by Canadian companies abroad. Overall, M&A activity involving Canadian projects exceeded US$1.7 billion (C$2 billion), and outbound investment by Canadian companies exceeded US$36 billion (C$45 billion).



Foreign investment by Canadian companies was spread broadly across a number of jurisdictions, including the United Kingdom, Mexico, Singapore, France, the US, Australia, Germany and Spain.



CANADIAN PURSUING M&A OPPORTUNITIES INTERNATIONALLY

Canadians are continuing to invest in more mature markets, including Europe and the US, and appear willing to pay relatively higher purchase prices for target companies and assets in more stable political and operating environments. Following multiple blockbuster deals in 2016, Canadian investors kept up the momentum of cross-border growth into the US as evidenced by AltaGas Ltd.'s US$6.7 billion acquisition of WGL Holdings, Inc. and Hydro One Limited's US$5.2 billion acquisition of Avista Corporation.

In 2017, Enbridge Inc. acquired a 49.9% ownership in the 497 MW Hohe See offshore wind project from EnBW, a German utility, who will retain the remaining interest. Enbridge has several projects under development in the European offshore wind market, including a 24.9% stake in the 400 MW Rampion wind project off the coast of England (expected to be fully operational in 2018), and a 50% interest in French offshore wind development company Éolien Maritime France SAS, which is pursuing three large-scale offshore wind projects that will produce a combined 1,428 MW of power and are subject to final investment decision. Northland Power's acquisition of Deutsche Bucht, a Germany-based 252 MW offshore wind project further highlights Germany as a smart energy leader. Germany's commitment to decarbonise power generation and phase out nuclear plants in the wake of the Fukushima nuclear disaster has led to a radical shake-up of the system, under the policy known as Energiewende (energy transition). This is the biggest programme of its sort seen to date in a developed nation. Focusing on making energy supply more efficient and cleaner, Germany's energy policies are the main reason for transformation from traditional to smart energy technologies.

Despite their recent acquisition by Enbridge, many of these assets could form part of the mix in 2018's M&A activity, as Enbridge announced on November 29, 2017 an intention to sell non-core assets as part of a strategic plan and outlook completed following the merger with Spectra Energy. Al Monaco, President and CEO of Enbridge, stated "We will rationalize our asset mix to a pure regulated pipeline and utility business model, which emphasizes low risk businesses and strong growth in our three crown jewel businesses: liquids pipelines and terminals, natural gas transmission and storage and natural gas utilities. Through this review, we've identified a total of $10 billion of assets that are non-core to Enbridge. In 2018, at least $3 billion of certain unregulated gas midstream and onshore renewables businesses will be sold or monetized".

Turning to the eastern regions of the globe, China's plans to increase its investment in renewable energy, especially solar and wind power, are poised to drive clean energy deals in the Asia-Pacific region. China's recent commitments to curb pollution, including its signing onto the Paris Agreement on Climate Change, also offer the country the opportunity to leverage its large domestic market in establishing economies of scale. In the largest renewable energy generation acquisition in history, Global Infrastructure Partners, through its fund Global Infrastructure Partners III, along with Canadian Public Sector Pension Investment Board, China Investment Corporation and other co-investors, acquired Equis Energy, the largest renewable energy independent power producer in the Asia-Pacific region, for US$5 billion.

At the same time, Canadians are pursuing higher returns in greenfield developments in less mature markets including Africa and Latin America. This has been particularly necessary in a climate of low oil prices which has hit the area hard in recent years, most notably in Brazil and Venezuela, which have seen much political unrest as their economies have felt the consequences. These regions have experienced rapid growth in power demand and policy initiatives targeting broader electrification. With an advantageous landscape in terms of solar and wind capabilities, the region has attracted interest from investors looking for growth potential. In a US$1.3 billion transaction, La Caisse de dépôt et placement du Québec, a long-term institutional investor, and CKD Infraestructura México, a consortium of Mexican institutional investors, will acquire 80% of a portfolio of eight wind and solar assets owned by Enel Green Power, a global leader in renewable energy.

Other M&A transactions by Canadian companies targeting foreign assets included:

British Columbia Investment Management Corporation and **Macquarie Infrastructure and Real Assets**, together with AMP Limited and Qatar Investment Authority, agreed to acquire a 50.4% stake in Endeavour Energy Pty Ltd., an Australia-based electricity distributor, for US$5.6 billion (including the assumed debt).	**Brookfield Asset Management Inc.** agreed to acquire TerraForm Global, Inc., a US-based company operating solar, wind, and hydro-electric generation assets, for US$1.2 billion and a 38.84% stake of TerraForm Power Inc., a US-based owner and operator of clean energy plants, for US$4.2 billion (including assumed debt).
Brookfield Renewable Energy Partners L.P. acquired a 25% stake in First Hydro Company, a UK-based water-fired power generation company, for US$255 million.	**Innergex Renewable Energy Inc.** and **Desjardins Group Pension Plan** acquired two wind farms located in France for US$113 million.
Public Sector Pension Investment Board acquired a 9.93% stake in Pattern Energy Group Inc., a US-based renewable generation and transmission company, for US$206 million and a 49% interest in the 182 MW Panhandle 2 wind project located in Texas for US$59 million.	**Alberta Investment Management Corporation**, together with the AES Corporation, agreed to acquire Sustainable Power Group, LLC, a US-based developer and electricity generation operator, for US$1.6 billion (including the assumed debt).
Brookfield Asset Management Inc. agreed to acquire 12 hydro plants in Spain, from Ferroglobe Plc, for US$375 million.	**Crius Energy Trust** acquired U.S. Gas & Electric, Inc., a US-based electricity transmission company, for US$173 million.
Algonquin Power & Utilities Corp. agreed to acquire a 25% stake in Atlantica Yield plc, a UK-based owner and manager of renewable energy, conventional power and electric transmission lines and other contracted revenue-generating assets, for US$623 million.	**Capital Power Corporation** acquired Decatur Energy Center, LLC, a natural gas-fired power plant located in Alabama, for US$441 million.

DOMESTIC DEAL FLOW

In addition to significant investments by Canadian companies abroad, 2017 continued to produce substantial domestic deal flow as investors looked to bolster their portfolios with yield-generating assets. Domestic acquisitions of operating assets included:

Innergex Renewable Energy Inc. agreed to acquire Alterra Power Corp., an operator of renewable energy projects, for C$1.1 billion.	**Axium Infrastructure Inc.** agreed to acquire a 76 MW portfolio of solar projects located in Ontario from TransCanada Corporation for C$540 million.
Fengate Capital Management Ltd. acquired three solar power plants located in Ontario (59.8 MW in the aggregate) from Canadian Solar Inc. for C$257 million.	**Capital Power Corporation** acquired various interests in the thermal power business of Veresen Inc. in Ontario and BC (588 MW in the aggregate) for C$500 million.
Public Sector Pension Investment Board agreed to acquire a 49% interest in the 143 MW Mont Sainte-Marguerite wind projects located in Québec for C$51 million and a 49% interest in the 183.5 MW Meikle wind project located in British Columbia for C$82 million.	**IKEA Canada Limited Partnership** acquired the 88 MW Wintering Hills wind facility for C$118 million.
BluEarth Renewables LP acquired four operating renewable energy facilities, including three run-of-river hydro facilities in BC and one wind facility in Ontario (85 MW in the aggregate).	**BC Hydro** acquired the remaining two-thirds interest in Waneta Hydroelectic Dam in BC from Teck Resources for $1.2 billion.

Energy Litigation

George Vegh

Julie Parla

Sam Rogers

Samuel Lepage

Key Cases in 2017

In 2017, there were a number of interesting cases with potential impacts on the energy sector. Highlights, not discussed elsewhere in this publication include the following:

BRITISH COLUMBIA

***Harrison Hydro Project Inc. v. Environmental Appeal Board,* 2017 BCSC 320**

The limited partner owners of five “run of river” hydro projects near Harrison Lake, BC, sought judicial review of a decision of the Environmental Appeal Board, which held that the (single) general partner was the holder of the water licence issued under the *Water Act* for all five of the projects, and not the five limited partnerships. As a result of the EAB’s decision, the “water rental rate” for each of the five projects was much higher than if the licences had been held by the limited partnership.

On judicial review, the BC Supreme Court held that the standard of review was reasonableness and that the EAB’s decision was reasonable because the “EAB Decision accords with the above-noted statutory and common law principles concerning limited partnerships”, which hold that limited partners must cede control of the business of a limited partnership to one or more general partners in order to receive the protection of limited liability.

An appeal was heard by the BC Court of Appeal in November 2017, and a decision is expected in early 2018.

***Kirk v. Executive Flight Centre Fuel Services,* 2017 BCSC 726**

The BC Supreme Court certified a “single-incident mass tort” arising from the spill of 35,000 litres of jet fuel from a tanker truck into a creek in the West Kootenay region of BC. This was the first class action of this kind to be certified in Western Canada. Certification was hotly contested by the Province, which acted as one of the defendants.

The plaintiff advanced claims for negligence, nuisance, and damages pursuant to the rule in *Rylands v. Fletcher* (which provides for strict liability where a person allows a hazardous substance on their land and it escapes). The Defendants raised many objections to the certification, but the proceeding was ultimately certified.

Although there has been no decision on the merits, the certification of the class should be kept in mind by owners when dealing with spills or other environmental emergencies at their sites. The clear indication is that courts are becoming more willing to allow groups of locally affected individuals to prosecute their claims as a class.

An appeal of the certification decision was launched and it is expected to be heard in 2018.

ALBERTA

There were a number of interesting developments in Alberta related to the electricity market change, which are addressed in the Alberta section of this publication.

Alberta Energy Regulator v. Grant Thornton Limited, 2017 ABCA 124

The "orphan wells" decision from the Alberta Court of Appeal generated significant press in 2017. The appeal arose from a decision of the Court of Queen's Bench, which held that there is an operational conflict between Alberta's *Oil and Gas Conservation Act* and *Pipeline Act* and the Federal *Bankruptcy and Insolvency Act*. Given that the BIA is federal legislation, it prevails in the event of a conflict, and a trustee of a debtor is permitted to choose which wells of the debtor are preserved for the secured creditors.

The Court of Appeal split 2 to 1 in favour of affirming the Queen's Bench's decision. The majority agreed that there was an operational conflict. The dissent disagreed with how the issue had been framed, and concluded that the obligations in relation to unproductive wells are not debts, but public duties created by valid provincial legislation.

Leave to appeal to the Supreme Court of Canada was granted in November 2017, and the appeal will be heard in 2018. Although the decision itself is largely confined to the oil and gas industry, the intersection between provincial legislation and the Federal *Bankruptcy and Insolvency Act* often arises in restructuring matters, and the Supreme Court's decision will have a broad impact across industry sectors.

ONTARIO

Rogers Communications Canada Inc. v. The Ontario Energy Board, 2017 ONSC 3959

A group of telecommunications carriers brought an appeal to Ontario's Divisional Court from a decision of the Ontario Energy Board on a "review and variance" motion.

As part of a utility's rate application, the Board had set the rate that the utility could charge carriers for using its poles at $37.05. The carriers had not had notice of this decision, and had not participated in the hearing. Accordingly, they brought a motion for review and variance pursuant to Board Rules 40-43.

As a result of the carrier's request, the Board conducted a hearing *de novo*, which involved the collection of evidence, answering of interrogatives, and oral argument. After hearing the evidence and argument, the Board increased the rate that the utility could charge to $41.28.

The carriers appealed on the basis that the process used by the Board was procedurally unfair, and that the Board erred in refusing to require the utility to produce an agreement between the utility and a 3rd party carrier who was not involved in the litigation. The Divisional Court rejected both arguments finding that: (i) the carriers had asked for a new hearing, which was what the Board conducted, and the Board thereafter "simply and reasonably" used the "latest available actual cost data to set the applicable pole attachment rate"; and (ii) that the agreement did not have to be disclosed because the utility disclosed the "essential information about the agreement".

Hirsch v. Ontario (Environment and Climate Change), **2017 CanLII 25365 (ON ERT) and** ***Wiggins v Ontario (Environment and Climate Change),*** **2017 CanLII 70687 (ON ERT)**

Ontario's Environmental Review Tribunal (ERT) released two interesting decisions arising from challenges to Renewable Energy Approvals (REA). Both were so-called "remedy" hearings that were conducted after the ERT determined the wind farm projects in question would either cause serious and irreversible harm to the environment or serious harm to human health.

Hirsch concerned the White Pines wind farm project in Prince Edward County, which was originally approved as a 27 turbine project. In 2016, the ERT found that the wind farm project would cause serious and irreversible harm to two species at risk: the little brown bat and the Blanding's turtle.

At the remedy hearing, the project proponent put forward mitigation plans that would reduce the size of the wind farm from 27 turbines to 9 turbines, removing the turbines most likely to cause the harm to little brown bats and Blanding's turtles. Although the party opposing the project argued that the ERT did not have jurisdiction to consider the plans given the extensive nature of the changes to the project, the ERT found that the plans would effectively mitigate the harm and therefore the project as modified by the mitigation plans.

Wiggins concerned the Fairview wind farm project in Clearview Township. In 2016, the ERT found that the wind farm project would cause serious and irreversible harm to little brown bats. The ERT also found that the project would cause serious harm to human health due the impact it would have on aviation safety in light of a nearby airport.

At the remedy hearing, the project proponent offered a mitigation plan that would address harm to little brown bats, but would not prevent the serious harm to human health caused by the proximity of the nearby airport. As a result, the REA revoked.

The contrasting results between *Hirsch* and *Wiggins* demonstrate the difficulty that proponents will face if the ERT finds that a project will cause serious harm to human health. The ERT will be cautious in evaluating potential remediation plans after finding a project will cause serious harm to human health, and it may be difficult or impossible to provide effective remediation – as in *Wiggins*.

Driver et al. v. wpd Canada Corporation et al., **2017 ONSC 3824**

This was a decision in a judicial review application concerning the White Pines wind farm project (the same wind farm project considered by the ERT in *Hirsch)*. Members of a local "heritage community" brought an application for judicial review on the basis that the wind farm was located in a "designated cultural heritage landscape".

The application was dismissed, and the court made a number of findings including that the standard of review of the Director's decision to issue the REA was reasonableness, that the decision to issue a REA must be considered in light of the priorities of the Province's green energy initiative (as enacted in the *Green Energy and Green Economy Act, 2009*), and that the process followed by the Director was procedurally fair. All of these findings should provide guidance to other proponents who may be faced with a judicial review.

As an addendum, in November 2017, another local group opposed to wind farms brought an application for a declaration against the proponent of the White Pines wind farm project seeking a declaration that the proponent's Feed-In-Tariff contract should have been cancelled when it became apparent that the proponent could not produce 75% of the contracted power. That litigation is in the early stages, although it will likely progress quickly given the nature of the proceeding.

QUÉBEC

Labranche v. Énergie éolienne des Moulins et al.

In *Labranche*, Énergie éolienne des Moulins, a limited partnership, is the subject of a class action arising from its for construction and operation of a wind farm. The class encompasses every person whose residence is within 4.8280 kilometres of the wind farm project. The class representative claims damages for the neighbourhood annoyances suffered by the class both during the construction and the past, on-going and future operation of the wind farm. It is interesting to note that Hydro-Québec, the public entity that awarded the supply contract which triggered the construction of the wind farm, is also named as a defendant in the proceedings for having allowed the construction of the wind farm at that specific location. The class action was authorized by the Superior Court of Québec in March 2016. The authorization was confirmed by the Court of Appeal in November 2016. The case was argued on its merits in late 2017, and a decision is expected shortly.

Importantly, in addition to damages, the class is seeking a permanent injunction from the court ordering the dismantling of the wind farm. If granted, that injunction would have broad implications for owners of wind farms.

Rivard v. Éoliennes de l'Érable and Blouin v. Parcs éoliens de la Seigneurie de Beaupré 2 et 3, s.e.n.c.

Similarly, *Rivard* and *Blouin* are class actions involving wind farm operators that have progressed in 2017. Unlike the *Labranche* case, the damages claimed by the classes in *Rivard* and *Blouin* only relate to neighbourhood annoyances suffered during the construction period. The class members are residents of the roads and tracks leading to the wind farms. Trial dates for these cases should be set in 2018.

Kruger inc. Master Trust v. Gercotech inc. (4335414 Canada inc.)

In *Kruger inc. Master Trust*, the court allowed the plaintiff's application for the reduction in the selling price of a biogas and power generation plant from a landfill site purchased from defendants. The selling price of $15M had been based on vendor warranties and representations with respect to the generating capacity of the facility and the cost of maintaining equipment to operate it. Immediately after the transaction, a biogas analysis revealed a high level of hydrogen sulphide (H_2S) and plaintiff was advised to replace the engine oil every 500 hours instead of the 1500 to 1800 hours represented by defendants. Even after plaintiff's efforts to resolve the problems caused by the hydrogen sulphide levels, the plant's performance was still below expectations and maintenance costs were much higher.

The court rejected the defendants' position that the plaintiff should have analyzed the biogas itself before the transaction, concluding that defendants knew about the importance of the quality of the biogas and used it to inflate the selling price, while voluntarily hiding the fact that the biogas contained high levels of hydrogen sulphide. As for the electricity production, the defendants made false representations with respect to the income projection by not informing the plaintiff of the plant's failure to meet Hydro-Québec's agreed production obligations. The plant failed three consecutive tests of 100 hours of uninterrupted production, the last test even causing an interruption in the production. Despite this, the defendants advised that Hydro-Québec's requirements had been met and that the production test had succeeded.

False representations were also made with regards to a “Smart Soil Technology” meant to increase biogas and electricity production by recirculating biogas in the site and using a software allowing automatic control of the valves, hence stabilizing electricity production. Based on defendants’ false representations, the court reduced the selling price to $6.4M. The defendants have appealed and the appeal should be heard in 2018.

ABOUT McCARTHY TÉTRAULT'S NATIONAL POWER GROUP

Our **Power Group** consists of more than 30 lawyers nationally, including the most experienced energy lawyers in Canada. Our principal areas of practice include project development, project finance, mergers and acquisitions, utility restructuring, privatizations and procurement. We also have extensive expertise in advising and representing clients in the area of energy regulation and litigation.

Drawing on our breadth of expertise and experience in the power and energy sectors, we provide practical and timely advice to our clients, and take a hands-on approach to resolving issues. We understand the complexities associated with developing, structuring, financing, approving and operating a variety of different types of power projects.

Our retainers on North American electricity matters include acting for Canada's major public and private electric generators, transmission and distribution utilities, major equity investors and developers of power projects, lenders to power projects and fuel and equipment suppliers to the power industry. We have acted on behalf of developers, lenders or investors in relation to:

- 75% of the renewable energy projects of over 30 megawatts procured by the Ontario Independent Electricity System Operator (IESO), and have represented the largest hydropower generators under IESO's "hydropower contract initiative";
- 21 of the 27 renewable energy projects awarded electricity purchase agreements by BC Hydro in its most recent Clean Power Call as well as over eight projects awarded EPAs under BC Hydro's Standing Offer Program; and
- more than 80% of the wind projects developed in Québec since Hydro-Québec's first major 1,000 MW RFP in 2003.

We have assisted clients with all aspects of power project development and financing, including energy regulation, grid inter-connection, real estate assembly and site-use planning, power purchase arrangements, construction and long-term financing, permitting and environmental, insurance, construction contracts, turbine supply contracts, tax structuring, joint venture and warranty arrangements.

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For more information please contact:

British Columbia

Sven Milelli
604-643-7125
smilelli@mccarthy.ca

Robin Sirett
604-643-7911
rsirett@mccarthy.ca

Alberta

Cameron Hughes
403-260-3675
chughes@mccarthy.ca

Kimberly Howard
403-260-3575
khoward@mccarthy.ca

Ontario

David A.N. Lever
416-601-7655
dlever@mccarthy.ca

Seán C. O'Neill
416-601-7699
soneill@mccarthy.ca

Québec

Louis-Nicolas Boulanger
514-397-5679
lnboulanger@mccarthy.ca

Marc Dorion, Q.C., Ad. E.
514-397-5676 | 418-521-3007
mdorion@mccarthy.ca

mccarthy tetrault

VANCOUVER
Suite 2400, 745 Thurlow Street
Vancouver BC V6E 0C5

CALGARY
Suite 4000, 421 7th Avenue SW
Calgary AB T2P 4K9

TORONTO
Suite 5300, TD Bank Tower
Box 48, 66 Wellington Street West
Toronto ON M5K 1E6

MONTRÉAL
Suite 2500
1000 De La Gauchetière Street West
Montréal QC H3B 0A2

QUÉBEC CITY
500, Grande Allée Est, 9e étage
Québec QC G1R 2J7

NEW YORK, US
55 West 46th Street, Suite 2804
New York, New York 10036

LONDON, UK
125 Old Broad Street, 26th Floor
London EC2N 1AR
UNITED KINGDOM

www.mccarthy.ca
email: info@mccarthy.ca