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Alternative Energy & Power

Alternative Energy & Power in Canada – Law and Practice

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INTRODUCTION

Contributing Editor

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Contributing Editor: Dennis P. Langen

Stikeman Elliott LLP Energy: Power, Energy: Regulatory; Energy: Oil & Gas – Transactional, Mergers & Acquisitions, Competition & Antitrust, Capital Markets. Offices in Vancouver, Calgary, Toronto, Montreal, Ottawa, New York, London, Sydney. Stikeman Elliott's Energy team has significant experience on matters related to the power and regulatory industries, including approval, development and operation of oil and gas wells, pipelines, storage facilities, petrochemical plants and oil sands developments, as well as power plants, generation facilities and transmission lines.

Our national power practice supports clients through all phases of conventional and renewable power projects and related transactions. The firm represents domestic and international project developers, utilities and financial players, as well as regulatory and government agencies. Developers, lenders and purchasers on some of Canada's largest generation and transmission projects rely on our counsel. Stikeman Elliott lawyers also have a proven reputation in energy regulatory matters throughout Canada, advising on many of the most complex undertakings in the sector in recent years. These initiatives include the construction and development of major projects to ongoing operations; supporting the regulatory elements of major acquisitions, divestments and development projects; and acting as counsel in complex regulatory proceedings, including appeal and judicial review proceedings. In addition, Stikeman Elliott has strong relationships with key policy and decision-makers in the highly regulated oil and gas and power industries. Lawyers frequently appear in proceedings related to the approval, development and operation of oil and gas wells, pipelines, storage facilities, petrochemical plants and oil sands developments, as well as power plants, generation facilities and transmission lines. The firm represents clients before the National Energy Board (NEB), the Alberta Energy Regulator, the Ontario Energy Board, the British Columbia Utilities Commission and the Manitoba Public Utilities Board, as well as Innovation, Science and Economic Development Canada and the Competition Bureau.

With appreciation for their significant input and assistance, the authors would like to recognize Jason Kroft, Michael Kilby, Patrick Duffy and Vincent Light.

Contributing Editor

Dennis P. Langen is a partner whose practice focuses on regulation of energy development, infrastructure and markets. He has experience and extensive knowledge in the areas of deregulated electricity markets, the economic regulation of electric utilities and in the permitting and approval of electricity facilities, including alternative and traditional generation, transmission and distribution. Given his experience, Dennis regularly advises clients on all aspects of federal and provincial energy regulation, including environmental, engineering, operational, indigenous, economic, market and compliance aspects. He represents independent system operators and electricity market participants (generators, renewable developers, importers and exporters) in respect of facility, economic, market and surveillance issues. He frequently appears, and advises clients in relation to proceedings, before the National Energy Board and the Alberta Utilities Commission. Dennis is also a Professional Engineer, and often applies his technical expertise when advising clients.

INTRODUCTION

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This is the inaugural Chambers Global Practice Guide for Alternate Energy and Power. It is being launched during an exciting and dynamic time in the evolution of the global electric energy and power industry.

The desire to de-carbonise and, to a lesser extent, to de-nuclearise power generation has been – and continues to be – a focus in many jurisdictions around the globe. At the same time, and in response, renewable generation in its various forms, including micro-generation, is viewed largely as the way of the future and is garnering more government attention and investor interest than ever before. Carbon phase-out and renewable energy targets are becoming commonplace, as are renewable energy incentive and subsidy programmes. Such change does not occur without creating regulatory, technical and commercial challenges. Governments are assessing their current regulatory, market and rule structures to determine how best to adapt and are doing so within the framework of existing long-lived transmission and distribution infrastructure investment that also needs to adapt to dynamic changes in power supply and consumption. Concurrently, infrastructure developers and investors are assessing the commercial impacts of these changes on existing generation and infrastructure, while focusing on the future and how the commercial landscape for new infrastructure investment is going to change.

Evolution within the electric and power industry is a constant. A decade or two ago, many jurisdictions contemplated and experienced material changes in the form of "unbundling" the then widely utilised vertically integrated electric utility model. Not unlike now, the need to adapt or create regulatory, market and rule structures was required to accommodate the unbundling of electric utilities into a mixture of generation, transmission and distribution segments, while also developing and implementing retail and wholesale supply and market regimes. However, the drivers for today's transformation, as well as the scope and magnitude of that transformation, are significantly different.

The changes relating to the unbundling of electric utilities were largely driven by government policy, with the goal of reducing the price of power for consumers through the creation, and opening, of markets in order to incentivise competition from both new and different investment. Today's drivers are multifaceted and complex. They include: geopolitical factors; the social and environmental awareness and involvement of consumers combined with reciprocal social and environmental governmental policy; and technological advancements in almost all aspects of the industry, including at the consumer level. That is, whereas the changes in the electricity industry that were experienced in the recent past were largely driven top-down though government policy, today's changes are in response to both top-down and bottom-up stimuli. Governments, the global populace, progressive energy consumers and new technology are driving much of the desire for change, with energy economics playing a smaller, but still important, role.

The scope and magnitude of unbundling electrical utilities involved altering the regulatory and commercial models that existed and did not involve much, if any, change to existing electrical infrastructure and how that infrastructure physically delivered electricity to the consumer. In contrast, the changes occurring and being contemplated today go well beyond regulatory and commercial models as they involve the development and implementation of new types of generation and new technologies which require integration into existing infrastructure. Indeed, the desire to replace dispatchable or steady-state carbon-based generation with non-dispatchable and intermittent renewable generation, like wind and solar, raises a real challenge from a reliability perspective at a time when consumers in developed countries view reliable electricity service as a right and not a privilege. This challenge has and continues to drive the need for the development and integration of energy storage technology, which in turn has the potential to cause other integration issues in respect of market and rule design. The current paradigm, which asks the question of whether an energy storage facility is "load" or "dispatchable generation", needs to evolve. Similarly, the integration of distributed generation technology, in the form of micro-generation and smart grid technology, like storage (eg, electric car batteries), raises further challenges regarding integration as it has never been seen at the electricity distribution level. For this reason, these concepts have the potential materially to disrupt market designs and rules, the physical infrastructure that is in place today, and the commercial and economic aspects of electricity infrastructure as a whole.

Notwithstanding that change is occurring, the full scope of that change has yet to be seen. Again, one need only look at the historic example of the unbundling of electric utilities. In Canada, only two of ten provincial jurisdictions unbundled their electricity industry, and of the eight that continued in a vertically integrated manner, approximately half have environments where publicly owned utilities are the only participants. The other half are either fully private or a mixture of public and private. That is, the evolution of the industry through unbundling did not fully materialise in Canada and the result is that the change brought about by unbundling was a matter of degree and not one of kind. However, unlike unbundling, the changes discussed above are driven in no small part by developments in new technology which tends to transcend government policy. In this way the degree to which the existing industry paradigm evolves will be significant, but only time will tell whether that evolution will result in an entirely new paradigm.

Indeed, even in the face of efforts to de-carbonise and the push for renewables to replace carbon-based generation, globally the need for carbon-based generation (either coal or natural gas), including new generation, will remain well into 2040. In 2017, the International Energy Agency (IEA) forecast that between 2017 and 2040, global energy needs will expand by 30% and during the same period, presumably to meet the expanding need for energy, a net global addition of 400 gigawatts of coal generation is forecast. At the same time, the IEA estimated that between 2017 and 2040, renewable energy generation will capture two thirds of global investment in electricity generation. This explosive growth in renewable energy (primarily solar and wind) will result, in the IEA's estimation, in renewable power generation representing 40% of global generation by 2040. In the European Union, this number is estimated to be twice that, at 80%.

Globally, the electric energy and power industry is changing and evolving and will continue to do so at a rate not likely to have been seen since its infancy. This means there is, and will continue to be, plenty of opportunity for those in the industry, including legal experts, to develop and apply their expertise. Flexibility and innovation, on the part of all, will be necessary for success. These are exciting times!

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The 'Law & Practice' sections provide easily accessible information on navigating the legal system when conducting business in the jurisdiction. Leading lawyers explain local law and practice at key transactional stages and for crucial aspects of doing business.

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Stikeman Elliott LLP national power practice supports clients through all phases of conventional and renewable power projects and related transactions. The firm's complementary regulatory and commercial expertise takes clients from initial development and permitting phases through commercial operations. Stikeman Elliott also has substantial dispute resolution experience in the power sector, having represented clients in major arbitrations, administrative hearings, trials and appeals, including to the Supreme Court of Canada. In light of the increasingly complex world in which energy businesses operate, the firm also provides in-depth expertise in such critical areas as market design/evolution, environmental law and Aboriginal relations. Stikeman Elliott represents domestic and international project developers, utilities and financial players, as well as regulatory and government agencies. Developers, lenders and purchasers on some of Canada's largest generation and transmission projects have relied on the firm's counsel. With appreciation for their significant input and assistance, the authors would like to recognize Jason Kroft, Michael Kilby, Patrick Duffy and Vincent Light.

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Glenn Zacher is a partner in the Litigation & Dispute Resolution Group and is Co-Head of the Energy Group. His practice focuses on complex commercial litigation and class actions, particularly in the energy sector, and on energy regulatory law. He has appeared before all levels of provincial courts and the Supreme Court of Canada and has conducted arbitrations and acted as counsel before various administrative tribunals, including the Ontario Energy Board (OEB) and the National Energy Board (NEB). Glenn's energy dispute/regulatory practice includes advising and representing public agencies and private sector companies (generators, marketers, transmitters, developers, lenders, etc.) before the OEB, NEB, and in litigation and appeal proceedings before the Ontario Superior Court, Divisional Court, Court of Appeal and Supreme Court of Canada.

Erik Richer La Flèche is a partner in the Corporate Group. He advises corporations, lenders and governments on M&A transactions and large capital projects (e.g., infrastructure, mining, energy and electricity) in more than 35 countries. He has acted on more than 10 wind power projects in Québec representing more than 50% of the wind power MW built in that province and he advises both the single largest industrial consumer of power in Québec and the largest buyer of export power from Québec. Erik frequently writes blogs on natural resources and electricity in Québec and is also frequently interviewed by the media to comment on PPP, infrastructure, mining, energy and anti-corruption matters.

Dennis P. Langen is a partner whose practice focuses on regulation of energy development, infrastructure and markets. He has experience and extensive knowledge in the areas of deregulated electricity markets, the economic regulation of electric utilities and in the permitting and approval of electricity facilities, including alternative and traditional generation, transmission and distribution. Given his experience, Dennis regularly advises clients on all aspects of federal and provincial energy regulation, including environmental, engineering, operational, indigenous, economic, market and compliance aspects. He represents independent system operators and electricity market participants (generators, renewable developers, importers and exporters) in respect of facility, economic, market and surveillance issues. He frequently appears, and advises clients in relation to proceedings, before the National Energy Board and the Alberta Utilities Commission. Dennis is also a Professional Engineer, and often applies his technical expertise when advising clients.

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1. General Structure and Ownership of the Power Industry

1.1 Principal Law Governing the Ownership and Structure of the Power Industry

The structure and ownership of the power industry varies among Canada's ten provinces, as each has its own legislature that makes laws governing the industry within the province, including the mandate and authority of the provincial utility regulator. Eight provinces maintain the traditional vertically integrated utility structure. In all but two of those provinces, the electric utility is a provincially owned corporation (a Crown corporation) that, for the most part, provides monopoly generation, transmission, distribution and retail supply services. Two provinces, Alberta and Ontario, have unbundled industry structures with their own unique features.

The Canadian federal government does not play a role in the structure and ownership of the power industry in Canada. The federal government has jurisdiction over the export of electricity from Canada and the construction and operation of international transmission lines and designated transmission lines that would cross provincial boundaries. Federal jurisdiction over these matters is exercised by the National Energy Board, pursuant to the *National Energy Board Act*. Certain federal jurisdiction also applies to the operation and production of power at nuclear facilities.

Structure and Ownership of the Power Industry in Canada

Western Canada
Province and approx. population 1. – Alberta 4,319,000
Crown, private or municipal ownership – Private and some municipal
Vertically integrated or unbundled – Unbundled
Primary legislation – Electric Utilities Act; Hydro and Electric Energy Act
Utility regulator – Alberta Utilities Commission

Province and approx. population 1. – British Columbia 4,849,000
Crown, private or municipal ownership – Crown and some private
Vertically integrated or unbundled – Vertical
Primary legislation – Utilities Commission Act; Clean Energy Act
Utility regulator – British Columbia Utilities Commission

Province and approx. population 1. – Manitoba 1,347,000
Crown, private or municipal ownership – Crown
Vertically integrated or unbundled – Vertical
Primary legislation – Public Utilities Board Act
Utility regulator – Public Utilities Board

Province and approx. population 1. – Saskatchewan 1,170,000
Crown, private or municipal ownership – Crown
Vertically integrated or unbundled – Vertical
Primary legislation – Power Corporation Act
Utility regulator – No regulator

Central Canada
Province and approx. population 1. – Ontario 14,319,000
Crown, private or municipal ownership – Crown, private and municipal
Vertically integrated or unbundled – Unbundled
Primary legislation – Electricity Act; Ontario Energy Board Act
Utility regulator – Ontario Energy Board

Province and approx. population 1. – Québec 8,440,000
Crown, private or municipal ownership – Crown and some municipal
Vertically integrated or unbundled – Vertical
Primary legislation – Loi sur Hydro-Québec (Hydro-Québec Act); Loi sur la Régie de l'énergie (Act respecting the Régie de l'énergie)
Utility regulator – Régie de l'énergie

Atlantic Canada
Province and approx. population 1. – New Brunswick 761,000
Crown, private or municipal ownership – Crown
Vertically integrated or unbundled – Vertical
Primary legislation – Electricity Act; Energy and Utilities Board Act
Utility regulator – New Brunswick Energy and Utilities Board

Province and approx. population 1. – Newfoundland and Labrador 528,000
Crown, private or municipal ownership – Crown and private
Vertically integrated or unbundled – Vertical
Primary legislation – Electrical Power Control Act; Public Utilities Board Act
Utility regulator – Newfoundland and Labrador Board of Commissioners of Public Utilities

Province and approx. population 1. – Nova Scotia 957,000
Crown, private or municipal ownership – Private and some municipal
Vertically integrated or unbundled – Vertical
Primary legislation – Public Utilities Act; Utility and Review Board Act
Utility regulator – Nova Scotia Utility and Review Board
Province and approx. population 1. – Prince Edward Island 153,000
Crown, private or municipal ownership – Private

Vertically integrated or unbundled – Vertical
Primary legislation – Electric Power Act; Island Regulatory and Appeals Commission Act
Utility regulator – Island Regulatory and Appeals Commission

1. Government of Canada, Statistics Canada, 2018 Q1.

Provinces That Have a Vertically Integrated Utility Structure
Of the eight provinces that have a vertically integrated utility structure, four have populations greater than one million people.

British Columbia's vertically integrated utility, British Columbia Hydro and Power Authority ("**BC Hydro**"), was established as a Crown corporation by statute. BC Hydro is responsible for generating, purchasing, distributing and selling electricity throughout the majority of the province, as well as the construction and operation of the vast majority of the transmission system in the province. Public utilities in British Columbia are regulated by the British Columbia Utilities Commission ("**BCUC**"), pursuant to the *Utilities Commission Act*. The BCUC regulates the rates charged by electric utilities and is responsible for regulating the construction and operation of facilities by electric utilities.

SaskPower was established as a vertically integrated Saskatchewan Crown corporation, pursuant to the *Power Corporation Act*. SaskPower is responsible for and has the exclusive right to supply, transmit, distribute and sell electricity in Saskatchewan. Saskatchewan does not have a public utilities regulator.

Manitoba's vertically integrated Crown corporation is Manitoba Hydro, which was was established by the *Manitoba Hydro Act*. It responsible for and has the exclusive right to supply, transmit, distribute and sell electricity in Manitoba. Manitoba Hydro is regulated by the Public Utilities Board, which exercises its authority pursuant to the *Public Utilities Board Act*.

Hydro-Québec is Québec's vertically integrated Crown corporation, which was established by the *Loi sur Hydro-Québec* (*Hydro-Québec Act*). Hydro-Québec has a monopoly on the distribution of electricity in Québec. It is regulated by the Régie de l'énergie, pursuant to the *Loi sur sa Régie de l'énergie* (*Act respecting the Régie de l'énergie*).

Alberta
In 1995, the *Electric Utilities Act* was enacted to restructure the Alberta electricity industry by unbundling the vertically integrated electric utilities into three functional units – generation, transmission and distribution. While the generation, transmission and distribution functions would remain subject to rate regulation, the policy objective of the Alberta government was to deregulate generation.

In 2001, an unregulated wholesale electricity market (the power pool) was established, where prices were and continue to be set by competitive market forces based on price and quantity bids from generators to the power pool and the demand for electricity purchased by load customers from the power pool.

Except for a limited number of municipalities that own generating facilities and transmission facilities, all such facilities in Alberta are investor-owned. Similarly, except for distribution systems owned by municipalities within their boundaries and by rural electric associations (cooperatives) within their service areas, all distribution systems in Alberta are investor-owned.

The Alberta Utilities Commission ("**AUC**") is the public utilities regulator in Alberta. It regulates the power industry pursuant to its authority under the *Electric Utilities Act*, the *Hydro and Electric Act* and the *Public Utilities Act*.

Ontario
Ontario's electricity sector was formerly vertically integrated with virtually all generation and transmission owned and operated by provincially owned Ontario Hydro, and distribution owned and operated by Ontario Hydro as well as more than 300 municipal utilities. In 1999-2002, the Ontario electricity sector was competitively restructured. Ontario Hydro was broken up into Ontario Power Generation ("**OPG**"), which continued to own and operate most of the Ontario Hydro's generation assets; Hydro One Networks Inc. ("**HONI**"), which continued to own and operate Ontario Hydro's transmission assets; and the Independent Market Operator, since renamed the Independent Electricity System Operator ("**IESO**"), which was mandated by the then-newly enacted *Electricity Act*, 1998, to manage the reliability of the provincial transmission grid, administer Ontario's wholesale electricity market and undertake electricity system planning. Restructuring also resulted in a consolidation of the more than 300 distribution utilities. Today there are fewer than 70, some of which are investor-owned and some of which remain municipally owned; government policy continues to encourage further consolidation.

Transmission and distribution utilities are rate-regulated by the Ontario Energy Board ("**OEB**") under the *Ontario Energy Board Act*. The OEB also regulates construction of transmission and distribution infrastructure. Several years ago, the Ontario government took steps to privatise HONI; today, the government owns less than 50% of HONI. There have also been recent initiatives to introduce new entrants and competition into the transmission sector.

There has been significant government intervention in the electricity sector since market opening in 2002, including various price freezes and other forms of price regulation; this effectively undermined any merchant generation market. Almost all new generation since 2002 has, as a result, been procured by the IESO (and its predecessor, the Ontario Power Authority) pursuant to government directives. When the market was restructured, it was intended that OPG, which owned the majority of generation in the province, would further divest its generation assets; in the interim, OPG was subject to a market power mitigation framework. This planned OPG divestiture did not transpire and today most OPG generation is rate-regulated by the OEB.

Recently, the IESO initiated a Market Renewal Program which, among other things, is aimed at moving away from government-directed procurements in favour of market solutions. Among other things, the IESO's Market Renewal initiative includes plans for an Ontario capacity market and capacity trade between Ontario and neighbouring provinces and states.

1.2 Principal State-Owned or Investor-Owned Entities

Alberta

There are approximately 120 generating units in Alberta. The principal investor-owned power generation entities are TransAlta Corporation, ATCO Power and Capital Power. ENMAX (wholly owned by The City of Calgary) owns power generation facilities both in and outside of Calgary. The City of Medicine Hat owns and operates a power plant within its boundaries.

There are two investor-owned transmission companies, AltaLink and ATCO Electric (and an affiliate), which own the bulk of the transmission facilities in Alberta. Transmission facilities are also owned by ENMAX, EPCOR (wholly owned by the City of Edmonton) and the City of Medicine Hat. Montana Alberta Tie owns and operates a merchant intertie that enables the import and export of electricity between Alberta and Montana, United States.

There are two investor-owned distribution companies that serve most of Alberta outside of the larger Alberta municipalities, FortisAlberta and ATCO Electric. The municipalities of Edmonton (through EPCOR), Red Deer, Calgary (through ENMAX), Medicine Hat and Lethbridge own and operate their own distribution systems.

British Columbia

Approximately 80% of the generation capacity in British Columbia is owned by BC Hydro and Columbia Power Corporation, also a Crown corporation. The remaining 20% is owned by private investors, including independent power producers that either consume electricity on site for industrial operations or, as required, sell it to BC Hydro. Approximately 92% of the transmission assets and approximately 93% of the distribution assets in British Columbia are owned by BC Hydro. FortisBC, an investor-owned corporation, owns the approximate 8% of remaining transmission assets and 4% of the distribution assets in the province. The remaining distribution assets are owned by municipalities.

Saskatchewan

The transmission, distribution and retail segments of the power industry in Saskatchewan, as well as almost all generation, are owned by SaskPower. Approximately 20% of installed generation is privately owned. Each of these projects sells electricity to SaskPower under long-term agreements.

Manitoba

Virtually all generation in Manitoba and the entirely of the transmission, distribution and supply segments are owned by Manitoba Hydro. There are two privately held wind power projects that sell electricity under long-term agreements to Manitoba Hydro.

Ontario

The former generation arm of Ontario Hydro, OPG, continues to own a majority of provincial generation capacity (principally nuclear and hydro generation). OPG is owned by the province. The balance of provincial generation is owned by a mix of investor-owned companies.

Approximately 98% of provincial transmission assets are owned by HONI, which until several years ago was owned by the province. The province now owns a minority stake in HONI. There have been some recent initiatives aimed at introducing new entrants and competition in the transmission sector.

Distribution facilities are owned by HONI (mainly rural distribution networks) and approximately 70 local distribution companies, some of which are investor-owned and some of which remain municipally owned.

Most electricity end-use consumers are served by local distribution utilities. Competitive electricity retailers serve some commercial and residential end-use consumers; however, government legislation and regulations have largely driven competitive retailers out of the low-volume residential market.

Québec

More than 90% of electricity production and nearly all transmission and distribution facilities are owned and operated by Hydro-Québec. The remaining facilities are owned by the private sector, nine small municipalities and cooperatives. Of all electricity produced in Québec, 99% is from renewable sources. Hydro-Québec operates three divisions:

Hydro-Québec Production generates electricity, TransÉnergie transmits electricity in the province and for export, and Hydro-Québec Distribution distributes and sells electricity to consumers in the province.

1.3 Foreign Investment Review Process

Investment Canada Act

Foreign investment in Canada's power industry (and mo st other industries) is subject to the federally regulated provisions of the *Investment Canada Act* ("**ICA**"), enacted by the federal government of Canada. Under the ICA, subject to certain exemptions, every acquisition of control by a non-Canadian of a Canadian business, even where the business is already controlled by a foreign investor, requires either a notification or detailed review under the ICA to ensure it is likely to be of "net benefit" to Canada.

A notification involves the filing of a form with prescribed information and is typically an administrative formality; it can be filed at any time up to 30 days after implementation of the investment. A review, on the other hand, is typically a pre-closing process that requires positive approval by Canada's Minister of Innovation, Science and Economic Development (the "Minister") before proceeding.

Thresholds for Review

Whether a transaction is subject to notification or to pre-closing review depends upon whether certain enterprise value or asset thresholds are satisfied. These thresholds generally depend on a number of factors, the most relevant of which to the power industry are as follows:

- *Transaction structure:* Indirect transactions in which the purchaser acquires the voting shares of a non-Canadian corporation that controls a Canadian business are generally exempt from a pre-closing review.
- *Identity of purchaser or vendor:* Where the purchaser or vendor is ultimately controlled by nationals of a WTO member country, and the purchaser is not a state-owned enterprise, a pre-closing review is only triggered where the Canadian business has an enterprise value of CAD1 billion. That threshold rises to CAD1.5 billion where the purchaser or vendor is ultimately controlled by nationals of a "trade agreement" country, which includes the United States and European Union countries.
- *Involvement of state-owned enterprises:* If the purchaser is a "state-owned enterprise", broadly defined to include entities that are influenced directly or indirectly by a foreign government, a pre-closing review is required where the Canadian business has a book value of assets of CAD398 million.

Review Process

Where a transaction is reviewable, the purchaser must file an application for review prior to implementing the investment and the parties are prohibited from implementing the investment until the Minister confirms that he or she is satisfied or is deemed to be satisfied that the investment is likely to be of "net benefit" to Canada." This decision is based on certain factors set out in the ICA and in view of any legally binding undertakings the purchaser is willing to make, which are typically required.

Information in an ICA application for review includes benchmark data about the Canadian business, such as historical, current and forecast revenues, employment levels and capital expenditures, as well as information about the citizenship of existing officers and directors. The purchaser is required to describe its future plans for the Canadian business with reference to these benchmarks.

Once the purchaser has filed a complete application for review, the Minister has a 45-day period within which to make a "net benefit" determination, which may be (and often is) unilaterally extended by the Minister for an additional 30 days, and may be extended further with the consent of the purchaser. During this time, counsel to the purchaser will typically answer questions from the Investment Review Division and engage in negotiations over the legally binding undertakings that the purchaser is willing to accept with respect to its plans for the Canadian business. Such undertakings often include committing to maintain a Canadian head office and specified minimum levels of Canadian senior management, capital expenditures, employment levels and various other matters.

National Security Reviews

Irrespective of the value of an investment, the acquisition of control of a Canadian business or investment to establish a new Canadian business may be subjected to a national security review under the ICA. Purchasers that receive notice of a potential or actual national security review are prohibited from implementing a proposed investment pending the outcome of the review.

Where the Minister, after consultation with the Minister of Public Safety and Emergency Preparedness, is satisfied that the investment would be "injurious to national security", the Governor-in-Council may "take any measures it considers advisable" to protect national security, including prohibiting implementation of the investment or requiring written undertakings from the purchaser.

The government has issued guidelines containing a non-exhaustive list of factors that will be considered in determining whether an investment would be "injurious to national security". They include the potential impact of the investment on the security of Canada's critical infrastructure, the supply of critical goods and services to Canadians, and the potential of the investment to enable foreign surveillance or espionage.

1.4 Principal Law Governing the Sale of Power Industry Assets

Depending on applicable legislation in provinces that have a vertically integrated structure, utilities may require the approval of their regulator or the provincial government in order to dispose of utility assets outside the ordinary course of business or to enter into specified transactions.

Alberta

The sale of generation assets requires approval of the AUC pursuant to the *Hydro and Electric Energy Act*. The owners of larger-scale transmission and distribution system assets in Alberta have been designated by regulation as an "owner of a public utility" under the *Public Utilities Act*, which, among other matters and subject to certain conditions, prohibits the issuance of shares or debt, the sale of assets outside the ordinary course of business, and a change in control, unless prior approval of the AUC is obtained.

For dispositions involving a change in control of a transmission or distribution utility or the sale of assets outside the normal course of business, the AUC conducts a public interest assessment and applies a "no harm" test under which it considers, among other matters, the industry experience and financial metrics of the proposed purchaser to ensure the continued safe and adequate service to customers at just and reasonable rates. The sale of transmission and distribution businesses in Alberta is not common. When such sales have occurred, the AUC has conducted a hearing process before issuing necessary approvals. If a transaction involves an asset sale rather than a sale of shares, the AUC's approval under the *Hydro and Electric Energy Act* would also be required.

Ontario

The OEB has authority to review and approve the sale or lease of transmission or distribution assets, or a change in control of licensed transmission and distribution companies. All amalgamations by transmitters or distributors are reviewable pursuant to provisions of the *Ontario Energy Board Act*; these provisions are referred to as the MAAD (mergers, acquisitions, amalgamations and divestitures) provisions. In reviewing MAAD applications, the OEB applies a "no harm" test, which requires the applicant to show that ratepayers will not be worse off as a result of the transaction.

Generators are also required to notify the OEB before purchasing any interest in transmission or distribution facilities; likewise, transmitters and distributors are required to notify the OEB of any proposed acquisition of generation facilities. The OEB has the discretion to undertake a review of such transactions.

1.5 Central Planning Authority

In the provinces that have a vertically integrated utility structure, overall planning of the electric system regarding reliability and sufficiency of supply may be managed by or among the utility, its regulator, or the provincial government.

Alberta

The *Electric Utilities Act* established the independent system operator, which operates as the Alberta Electric System Operator ("**AESO**"). The AESO has numerous statutory responsibilities to, among others, assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs, and make arrangements for the expansion of and enhancement to the transmission system. Every second year the AESO produces a Long-term Transmission Plan ("**LTP**") for the entire province, which identifies the timing and location of current and future transmission needs over a 20-year period. The AESO also produces a Long-term Outlook every two years that forecasts electricity demand and generation in the province, looking forward 20 years, which helps inform the LTP.

The AESO has no authority to plan for the development of generation to meet the forecast electricity needs of Alberta. The development or retirement of generation facilities is intended to be driven by economics through price signals from Alberta's competitive wholesale electricity market. However, the AESO has the responsibility to administer the Renewable Electricity Program under which the AESO conducts competitive procurement auctions in accordance with the Alberta's government policy and pursuant to the *Renewable Electricity Act*.

Although the AESO does not own any transmission or distribution facilities in Alberta, it is responsible for directing the safe, reliable and economic operation of Alberta's interconnected electric system (transmission, distribution and generation) ("**AIES**"). To that end, the AESO is responsible for making technical rules regarding the operation of the AIES and for establishing and monitoring compliance with Alberta's reliability standards. The AESO also coordinates reliability with electrically interconnected jurisdictions in Canada and the United States.

The AESO is also responsible for providing "system access service" to the transmission system through the use of the facilities owned by the transmission utilities.

Ontario

The IESO and provincial government, along with input from local distribution utilities, are responsible for bulk and regional electricity system planning. The IESO and government regularly issue a long-term energy plan ("**LTEP**"), which identifies provincial bulk system needs; and regional plans, which identify regional system needs. Generation needs identified in the LTEP or regional plans have to date been addressed through government-directed procurements, including a number of major renewable procurements like Ontario's feed-in tariff (FIT) program. Going forward, the province and IESO intend that more generation be procured through market solutions like the proposed new provincial capacity market.

Transmission and distribution needs identified in the LTEP and regional plans are addressed by transmission and distribution utilities which must apply to the OEB, with support of the IESO, to construct new transmission and distribution facilities and include the costs of such facilities in their rate base.

1.6 Material Changes in Law or Regulation

Alberta

In 2015, the provincial government announced its Climate Leadership Plan ("CLP") under which it established as policy the phase-out of coal-fired generation by 2030 and set a target of at least 30% of Alberta's electricity coming from renewable sources by 2030. In order to respond to the transition off coal and the integration of more renewable and natural gas generation, the provincial government decided to establish a capacity market.

The Renewable Electricity Act, which is a product of the CLP, came into force in March 2017 and prescribed the 30% by 2030 target and, to that end, established the renewable electricity program ("REP") for the competitive procurement of renewable electricity by the AESO. The REP involves a series of competitive procurement auctions for the right to construct and operate projects, with a target of up 5,000 MW of renewable electricity by 2030.

In June 2017, the provincial government enacted An Act to Cap Regulated Electricity Rates, which caps electricity rates payable by consumers for energy costs on regulated electricity service at 6.8 cents/kWh. The change leaves electricity retailers unaffected, as any amounts in excess of the price cap are paid by the provincial government.

On 19 April 2018, the provincial government introduced Bill 13 in the legislature, An Act to Secure Alberta's Electricity Future, which provides for, among other matters, the establishment and operation by the AESO of a capacity market in Alberta. Bill 13 was passed in the legislature in June 2018 and all provisions relating to the capacity market will be in force by no later than 1 August 2018. The capacity market is expected to commence operation in November 2021, following the initial base auction process that will run from November 2019 to June 2020, followed by two rebalancing auctions. The AESO engaged extensively with stakeholders and other government agencies regarding the AESO's comprehensive market design for the capacity, energy and ancillary services markets, which was finalised at the end of June 2018. The AESO is currently engaged with stakeholders regarding the development of rules necessary to conduct the auction process and establish and operate the capacity market. The rules package is expected to be filed with the AUC in early January 2019, for approval in early July 2019.

Ontario

In mid-2017, the Ontario government enacted the *Ontario Fair Hydro Plan Act*, 2017 ("**OFHPA**"), the purpose of which is to alleviate electricity price increases. The OFHPA defers collection of approximately 25% of electricity costs for a period of approximately five years and provides for the subsequent phased-in collection of those deferred costs, plus carrying charges, over an approximately 30-year period. This scheme, which will defer over CAD20 billion in electricity costs, is being financed through an OPG-related trust which purchases, securitises and sells through bond issuances, the deferred amounts.

The IESO is currently undertaking a Market Renewal Program which is aimed at transitioning Ontario from government-directed supply procurement to market solutions, including the development of an Ontario capacity market and the enabling of capacity trade between Ontario and neighbouring provinces and states. The IESO is in the process of formulating the necessary market rule changes to implement its Market Renewal initiative over the next two to three years.

1.7 Announcements Regarding New Policies

Federal

In August 2017, Environment and Climate Change Canada released its "Technical Paper on the Federal Carbon Pricing Backstop", proposing an initial minimum backstop price of CAD10/tonne beginning in 2019, and increasing by CAD10 per year thereafter until the carbon price reaches CAD50/tonne in 2022 for provinces that have not implemented a carbon emissions price by 2019, or which do not meet the federal benchmark price. Draft legislation for the pricing scheme has been released and provinces have been given a deadline of 1 September 2018 to either develop their own carbon pricing scheme or accept the federal backstop price.

1.8 Unique Aspects of the Power Industry

In response to announced and expected solicitations by states in the northeastern United States for the delivery of incremental "clean energy", there may be significant opportunities in Canada to develop major transmission infrastructure to deliver electricity from Canadian hydro and wind sources in response to requests for proposals.

2. Market Structure, Supply and Pricing

2.1 Structure of the Wholesale Electricity Market

Only Alberta and Ontario have established wholesale markets through which electricity is exchanged and the wholesale price of electricity is set by competition. The other provinces have vertically integrated utilities, and the prices (i.e. rates) paid by consumers for delivered electricity reflect the bundled costs of generation, transmission and distribution approved by the provincial regulator. In provinces that provide for the purchase of electricity by the utility from independent power producers ("**IPPs**"), the approved cost of electricity purchased from IPPs is included in consumer electricity rates.

Alberta
The AESO operates and administers the power pool in accordance with the *Electric Utilities Act*. The Alberta power pool currently operates as an hourly auction, where all generators (above 5 MW) must offer all of their power into the market, and must comply with the AESO's dispatch instructions. Generators are dispatched in order of ascending price offers to meet demand in real time, with the marginal dispatched generator setting the system marginal price every minute. All generators are paid the "pool price", which is the weighted average of the system marginal price for an hour. Prices are set province-wide, and there is no locational or nodal pricing in Alberta.

Ontario
The wholesale electricity market, administered by the IESO, includes an hourly spot market. Initially wholesale prices were to be uniform across the province, with the eventual transition to locational marginal pricing. Subsequent amendments to the *Electricity Act* effectively replaced Ontario's short-lived wholesale market with a "hybrid market", whereby new generation was developed through government-directed procurements. Generation continues to be scheduled and dispatched through the IESO spot market; however, generators are paid for their output pursuant to long-term power purchase agreements ("**PPAs**"). Generators thereby receive both IESO market settlements and out-of-market top-up payments for the difference between what they earn in market revenues and what they are owed pursuant to their PPAs. Likewise, the province's dominant generator, OPG, receives market settlements from the IESO as well as top up payments to reflect the difference between what OPG earns in market revenues and what it is owed pursuant to generation rates set by the OEB. These out of market adjustment payments that are made to Ontario generators and other suppliers are referred to as the "Global Adjustment". The commodity price of electricity in Ontario is therefore composed of hourly wholesale market spot price, the Global Adjustment and other uplift charges, e.g. costs for ancillary services, administrative price charges, etc.

The *Electricity Act* and the *Ontario Energy Board Act* require that residential small business consumers pay the true cost of power over time; however, the legislation also mandates a regulated price plan ("**RPP**") to reduce residential and small business consumers' exposure to price volatility. Under the RPP, residential and small consumer rates are reset biannually.

2.2 Imports and Exports of Electricity
The export of electricity from Canada is regulated by the National Energy Board through the issuance of blanket electricity export permits issued pursuant to the *National Energy Board Act*. There are no federal permits required for electricity imports.

Imports and exports between Canadian provinces are permitted, subject to market rules and tariff terms and conditions applicable in the importing and exporting provinces.

Ontario
IESO market rules provide for inter-jurisdictional energy trade. Ontario is currently developing market rules to enable the export of capacity; these new rules are intended to be in place by the end of 2018. In two or three years, as part of developing a capacity market, the IESO also intends to enable capacity imports.

At present, market participants that wish to export electricity from Ontario to other jurisdictions must successfully bid into the IESO spot market and correspondingly offer into neighbouring markets (the same goes for imports). Ontario does not allow market participants to purchase firm physical transmission rights and therefore exports/imports can be curtailed due to internal transmission congestion or congestion on the "interties" connecting Ontario and neighbouring jurisdictions. Market participants may, however, purchase financial transmission rights in the IESO transmission rights market as a hedge against transmission congestion on the interties.

2.3 Supply Mix for the Entire Market
Canadian Electricity Supply Mix

Jurisdiction Canada total
Total 2016 generation (TWh) [1] – 652.4
Hydro 59% [2]
Natural gas 10%
Coal 9%
Nuclear 15%
Wind 5%
Solar < 1%
Petroleum < 1%
Biomass/fuel Geothermal 2%

Western Canada
Jurisdiction Alberta
Total 2016 generation (TWh) [1] – 82.3
Hydro 3%
Natural gas 40%
Coal 47% [3]

Nuclear -
Wind 7%
Solar -
Petroleum -
Biomass/fuel Geothermal 3%

Jurisdiction British Columbia
Total 2016 generation (TWh) 1. – 74.5
Hydro 88%
Natural gas 1%
Coal -
Nuclear -
Wind 1%
Solar -
Petroleum < 1%
Biomass/fuel Geothermal 9%

Jurisdiction Manitoba
Total 2016 generation (TWh) 1. – 36.6
Hydro 97%
Natural gas < 1%
Coal < 1%
Nuclear -
Wind 2%
Solar -
Petroleum < 1%
Biomass/fuel Geothermal < 1%

Jurisdiction Saskatchewan
Total 2016 generation (TWh) 1. – 24.4
Hydro 13%
Natural gas 34%
Coal 49%
Nuclear -
Wind 3%
Solar -
Petroleum < 1%
Biomass/fuel Geothermal 1%

Central Canada
Jurisdiction Ontario
Total 2016 generation (TWh) 1. – 156.0 1.
Hydro 23% 4.
Natural gas 28% 4.
Coal -
Nuclear 35% 4.
Wind 12% 4.
Solar 1% 4.
Petroleum < 1% 4.
Biomass/fuel Geothermal 1% 4.

Jurisdiction Québec
Total 2016 generation (TWh) 1. – 207.2
Hydro 95%
Natural gas < 1%
Coal -
Nuclear -
Wind 4%
Solar -
Petroleum < 1%
Biomass/fuel Geothermal 1%

Atlantic Canada
Jurisdiction New Brunswick
Total 2016 generation (TWh) 1. – 15.2
Hydro 21% 2.
Natural gas 15%
Coal 21%
Nuclear 30%
Wind 6%
Solar -
Petroleum 4%
Biomass/fuel Geothermal 3%

Jurisdiction Newfoundland and Labrador
Total 2016 generation (TWh) 1. – 41.8
Hydro 95%
Natural gas 2%
Coal -
Nuclear -
Wind < 2%
Solar -
Petroleum 2%
Biomass/fuel Geothermal < 2%

Jurisdiction Nova Scotia
Total 2016 generation (TWh) 1. – 9.7
Hydro 9% 2.
Natural gas 13%
Coal 64%
Nuclear -
Wind 11%
Solar -
Petroleum 3%
Biomass/fuel Geothermal 2%

Jurisdiction Prince Edward Island
Total 2016 generation (TWh) 1. – 0.6
Hydro -
Natural gas -
Coal -
Nuclear -
Wind 98%
Solar -
Petroleum 1%
Biomass/fuel Geothermal < 1%

[1.] Electricity production in 2016: National Energy Board, Canada's Energy Future 2016: Province and Territory Outlooks.

[2] Includes wave and tidal power.

[3] In early 2018, approximately 1,500 MW of coal-fired generation in Alberta was either retired or mothballed. The mothballed units will be converted to natural gas fired generating units.

[4] 2018 installed capacity in Ontario.

2.4 Principal Laws Governing Market Concentration Limits

Federal

Federal competition law is governed by the Competition Act. Transactions that involve a "merger" may be subject to review by and/or may require certain clearances from the Commissioner of Competition ("Commissioner"). The Competition Act defines "merger" very broadly: "…the acquisition or establishment, direct or indirect, by one or more persons, whether by purchase or lease of shares or assets, by amalgamation or by combination or otherwise, of control over or significant interest in the whole or a part of a business of a competitor, supplier, customer or other person." The substantive test applied by the Commissioner in deciding if a merger will ultimately be challenged following a review is whether it "would or would be likely to prevent or lessen competition substantially" in a relevant market.

Certain large transactions, measured primarily based on transaction-size and party-size thresholds being exceeded, trigger mandatory pre-merger notification filings with the Commissioner and such transactions cannot close until a statutory waiting period has expired and/or the Commissioner's review has been completed. The Competition Act provides a process to obtain an advance ruling certificate or similar comfort from the Commissioner that he or she will not challenge the proposed transaction, which among other things, allows parties to complete their transaction with substantive comfort that a post-closing challenge is unlikely and in some cases exempts the transaction from the formal pre-merger notification filing requirement.

Alberta

In Alberta, "offer control" is capped. Offer control means the ultimate control and determination by a market participant of the "price-quantity" offers made to the power pool in respect of the maximum capability of one or more generating units. Offer control is set by regulation at a maximum of 30% of the sum of maximum capability of generating units in Alberta and is determined by the Alberta Market Surveillance Administrator at least annually.

Ontario

As part of deregulation of the Ontario electricity sector and the opening of the market in 2002, the province mandated that Ontario's dominant generator, OPG (the former generation arm of Ontario Hydro), be required to further divest its generation assets. In the interim, OPG was subject to a market power mitigation framework under which OPG was required to rebate to ratepayers revenues in excess of a weighted average spot market price. As a result of ensuing policy and regulatory changes, OPG did not end up divesting its generation portfolio. Consequently, in 2006, most OPG generation (nuclear and hydro) was made subject to OEB cost of service rate regulation.

2.5 Agency Conducting Surveillance to Detect Anti-Competitive Behaviour

Alberta

The Market Surveillance Administrator ("**MSA**"), established by the *Alberta Utilities Commission Act*, has responsibility to carry out surveillance in respect of the supply, generation, transmission, distribution, trade, exchange, purchase or sale of electricity in Alberta. The MSA has authority to investigate (i) possible contraventions of legislation governing the electric industry, (ii) when it appears to the MSA that the conduct of a market participant does not support the fair, efficient and openly competitive operation of the electricity market and (iii) for any matter that relates to or affects the structure and performance of the electricity market. The MSA has the authority to enter and inspect premises, make inquiries of employees and former employees, demand the production of records, temporarily remove documents and make copies, and request access to computer systems to obtain records from data. The MSA has the authority to refer non-compliance matters to the AUC for consideration and potential enforcement measures.

Ontario

There are two agencies that monitor anti-competitive behaviour and undertake enforcement activity: (i) the Market Surveillance Panel ("**MSP**"), a panel of the OEB; and (ii) the Market Assessment and Compliance Division ("**MACD**"), a division of the IESO. The MSP monitors, investigates and reports on IESO market design and structural issues and on activities and behaviour of market participants, which may include market manipulation and gaming. The MSP records its findings and recommendations in semi-annual reports published by the OEB. The MSP's recommendations often include broad proposals for remedying market design flaws and inefficiencies and curbing inappropriate or anomalous behaviour. The MSP has broad investigatory powers, which include the power to issue subpoenas for document production, compel testimony and undertake searches and seizures; however, the MSP does not have any enforcement authority.

MACD monitors the operation of the market and compliance with applicable market rules and reliability standards. MACD does this through prevention, monitoring, auditing, investigation and enforcement activities. In addition to monitoring and enforcing compliance with the market rules and reliability standards, MACD enforces compliance with the IESO's general conduct rule which proscribes conduct aimed at undermining, manipulating, interfering with or exploiting the market. MACD's enforcement authority includes the authority to levy substantial financial penalties.

3. Climate Change Laws and Alternative Energy

3.1 Principal Climate Change Laws and/or Policies

Alberta

In 2015, Alberta published its *Climate Leadership Plan*, which included a number of legislative changes including, among others, the introduction of a carbon emissions pricing regime, stricter emissions intensity reduction targets for large facilities, and a renewable electricity target of 30% by 2030. The *Climate Leadership Act*, which came into force on 1 January 2017, established a carbon pricing regime using a CAD20/tonne levy in 2017, and a CAD30/tonne levy for 2018 for various types of fuels. However, most large emitters will be exempt from this carbon levy due to registration, reporting, remittance and emissions reduction obligations under the *Specified Gas Reporting Regulation* and the *Carbon Competitiveness Incentive Regulation*, made under the *Climate Change Emissions and Management Act*.

The *Carbon Competitiveness Incentive Regulation* requires facilities emitting more than 100,000 tonnes of carbon dioxide equivalent per year (or facilities that opt-in so they may apply for a carbon levy exemption) to meet product-specific emissions intensity benchmarks. Most benchmarks are based on 80% production-weighted average emissions intensity, which means the 20% least emissions-intensive competitors face no *Carbon Competitiveness Incentive Regulation* compliance costs. Where emissions exceed the benchmark, the facility must reduce its net emissions by applying emissions offsets, emissions performance credits or fund credits against its actual emissions level. The purchase and use of fund credits to meet emissions targets is unlimited; however, the use of other credits is capped, such that a facility may address only a portion of its excess emissions through performance credits and emissions offsets, which expire dependent on their vintage.

British Columbia

In 2010, British Columbia enacted the *Clean Energy Act*, which established a mandate for BC Hydro to pursue the province's energy objectives of energy self-sufficiency, demand-side management and conservation measures to reduce electricity consumption by 66% and generate at least 93% of electricity in British Columbia from clean or renewable resources, among other targets. The province has also set targets to achieve emissions reductions of up to 80% below 2007 levels by 2050.

Saskatchewan

The *Management and Reduction of Greenhouse Gases Act* and associated regulations in Saskatchewan were passed in 2010, with portions of the Act coming into force on January 1, 2018. The Act provides for the provincial government to set greenhouse gas emission baselines, and annual reduction targets for emitters producing in excess of 1,500,000 tonnes of carbon dioxide equivalent per year.

Manitoba

The *Climate Change and Emissions Reductions Act* mandates a reduction of carbon emissions of at least 6% below 1990 levels, and restricts the use of coal for power generation, except for cases of emergency. The *Emissions Tax on Coal and Petroleum Coke Act* imposes a tax on coal and petroleum coke purchased for use and consumption in Manitoba, including power generation purposes.

Ontario

In an effort to allow Ontario to meet its greenhouse gas reduction targets of 15% below 1990 levels by 2020, 37% below 1990 levels by 2030 and 80% below 1990 levels by 2050, Ontario introduced the *Climate Change Mitigation and Low Carbon Economy Act in 2016* which provides the legal foundation for its cap-and-trade program. The program came into effect in 2017 and sets an initial cap on emissions equal to 142,332,000 allowances (one allowance is equal to one tonne of carbon dioxide equivalent "CO2e"), declining annually in accordance with Ontario's emissions targets.

The cap-and-trade program requires emitters of at least 25,000 tonnes of C02e annually and fuel supplier of more than 200 litres per year to participate and provides a voluntary opt-in mechanism for emitters of 10,000 to 25,000 tonnes of C02e annually (collectively, "capped emitters"). Capped emitters must procure a number of allowances equal to their emissions in a given compliance period. Allowances are typically procured by way government auction or issued free of charge to certain capped emitters who meet eligibility thresholds. Following the first compliance period (2017-2020), it is expected that the number of free allowances distributed to industry will decrease substantially.

The Ontario government generates funds from the program by selling allowances through government run auctions at which a regulated floor price is set. Ontario's cap-and-trade program is linked with similar programs in Québec and California under the Western Climate Initiative and joint auctions four times a year. Pricing of allowances remains subject to supply and demand, but due to a current surplus of credits, is currently around the CAD15 floor price, which increases annually as a function of the Consumer Price Index.

The recently-elected Premier of Ontario has declared his intention to dismantle the province's cap-and-trade program; however, details are not yet available.

Québec

Québec has adopted a cap and trade system for greenhouse gas emissions allowances. Hydro-Québec PPAs provide that "green credits", if any, are for the benefit of Hydro-Québec.

3.2 Principal Law and/or Policies Relating to the Early Retirement of Carbon-Based Generation

Federal

The Government of Canada has enacted regulations limiting the intensity of emissions from new and old coal-fired generation projects to 420 tonnes per gigawatt hour per year. Coal-fired generation plants must meet these emissions standards or retire at the end of their useful life, currently set by regulation at 50 years.

Alberta

The provincial government, as part of its *Climate Leadership Plan*, entered into off-coal agreements with the owners of all six coal-fired power plants in Alberta with anticipated service lives beyond 2030 to cease operations by 2030 in exchange for approximately CAD1.3 billion in total compensation. Under the agreements, the government has agreed to make annual payments to the owners until 2030 to cover the expected remaining undepreciated value of the generation assets beyond 2030, in exchange for commitments to reinvest certain amounts in the electric industry in Alberta, as well as the maintenance of a significant business presence in Alberta.

British Columbia and Manitoba

British Columbia's *Clean Energy Act* restricts the operation and use of thermal generation by BC Hydro, except for cases of emergency or for transmission support services. The *Manitoba Climate Change and Emissions Reductions Act* mandates that Manitoba Hydro must not use coal to generate power after 31 December 2009, except for emergency operations. Consequently, Manitoba Hydro utilises one coal-fired generator for emergencies only.

Ontario

Pursuant to the *Cessation of Coal Use Regulation* (2007), Ontario mandated the retirement of all coal-based generation facilities, or to convert them to cleaner-burning fuels by 2015 and, in accordance with the Regulations, Ontario phased out its last remaining coal-fired generation facility in 2014. Ontario has since enacted the *Ending Coal For Cleaner Air Act* which stipulates that coal cannot be used in future to generate electricity in Ontario.

3.3 Principal Law and/or Policies to Encourage the Development of Alternative Energy Sources

Alberta

As previously referenced, the provincial government established the Renewable Electricity Program ("**REP**"), pursuant to the *Renewable Electricity Act*, in an effort to achieve its target of obtaining at least 30% of electricity production from renewable sources by 2030 (being approximately 5,000 MW).

The first REP procurement competition was completed in December 2017, with the AESO procuring 595.6 MW of renewables from four proponents at a weighted average price of CAD37/MWh and with a target in-service date in December 2019. The AESO commenced two further REP rounds in March 2018 for the competitive procurement of approximately 300 and 400 MW of renewable electricity, respectively. Both rounds will be awarded in December 2018, with a target in-service date in June 2021. Round 2 has a requirement that a project must include a 25% threshold level of equity participation by indigenous communities.

The payment mechanism for the first round of REP was based on an Indexed Renewable Electricity Credit ("**REC**") set out in a 20-year Renewable Energy Support Agreement ("**RESA**") between the AESO and each successful bidder. The amount of support paid for the renewable project will be determined based on the difference between the bid price (strike price) and the pool price. The IREC paid is automatically adjusted so that when the pool price is below the bidder's strike, the bidder will be paid the difference between those values and when the pool price rises above the strike price, the bidder will be required to pay the AESO the amount above the strike price. As outlined in the *Renewable Electricity Act*, the government will provide funding for the cost of each RESA to the AESO on a monthly basis, for payment to the generators that are counterparties to a RESA.

Renewable generation projects are also eligible for emissions performance credits under the *Carbon Competitiveness Incentive Regulation*, which can be consumed to offset emissions costs from other operations, or sold in the marketplace to other regulated emitters.

British Columbia

Pursuant to the *Clean Energy Act*, BC Hydro is obligated to develop and file with the provincial government an integrated resource plan with a view to meeting the government's target of 93% renewable electricity generated on an annual basis. BC Hydro also administers feed-in tariff and standing offer programs for smaller generation projects (up to 15 MW) for fixed volumes and prices on an annual basis. However, BC Hydro has not yet set any volumes or prices for its Standing Offer Program for 2018 and beyond, as the appropriate price and volume for the Standing Offer Program continues to be under review.

Saskatchewan
SaskPower has committed to a target of 50% generation capacity from renewables by 2030, including 30% from wind power, despite no legislated requirement to do so. Included in its plans for procuring new renewables are competitive procurement processes for up to 120 MW of solar projects by 2025 and 1,600 MW of wind projects by 2030. The first competitions closed in Q4 of 2017, and are expected to award long-term power purchase agreements to approximately 10 MW for solar projects, and approximately 200 MW for wind projects.

Ontario
In 2009, the provincial government promulgated the *Green Energy and Green Economy Act* to encourage a dramatic increase in renewable resources. The centrepiece of the legislation is a feed-in tariff ("**FIT**") program. The program provides stable, standard-offer prices for electricity generated from renewable resources, with costs borne by rate payers.

Contracts are procured by the Ontario Power Authority through a standard RFP process and priority is awarded to projects with Aboriginal, community group, education, or health provider participation. FIT contracts have a 20-year term (40 years for waterpower projects), and in most cases there is no generation capacity limit. The FIT program also includes a program aimed to procure small-scale generation of 10 kW or less from homeowners and other micro-project developers (the microFIT program). Prices vary based on renewable energy source, project size, project participant and production timing. Several years after the introduction of FIT, surplus generation conditions and concerns about the over-market prices paid to renewable developers caused Ontario to substantially slow renewable generation procurements. In an attempt to address these concerns, Ontario also implemented an annual assessment of FIT prices which has resulted in downward pricing of between 50% and 75% for new procurement. At the end of 2017, Ontario had approximately 18,300 MW of renewable generation in operation or under construction, which is in line with its original goal of 19,700 MW by 2018.

4. Generation

4.1 Regulatory Process for Obtaining All Approvals to Construct and Operate Generation Facilities

The specific legislative and regulatory requirements for approvals to construct and operate a generation facility vary as between provinces. Depending on the scale of a project, an environmental screening or an environmental assessment may be required. In some jurisdictions, the regulator may conduct public hearings or proceedings to consider applications before issuing approvals.

Alberta
The construction and operation of a power plant in Alberta requires the approval of the AUC, pursuant to the *Hydro and Electric Energy Act*. The AUC must have regard to the social, economic and environmental effects of a project to determine whether it is in the public interest. Because Alberta's wholesale electricity market is intended to send price signals for generation development and retirements, the AUC must not consider the economics of a project and whether the electricity to be produced by a generator is needed in Alberta. Larger-scale generation projects that are opposed by affected parties may be subjected to a public hearing process. The AUC endeavours to issue a decision within three months of concluding the process.

Before the AUC can approve the construction of a hydroelectric project, the provincial legislature must first pass a bill authorising the hydroelectric development, following which the AUC can issue the requisite approval. Generation projects having a capacity of 100 MW or greater that will use a non-gaseous fuel and hydroelectric developments having a capacity of 100 MW or greater require an environmental impact assessment to be conducted in accordance with the *Environmental Protection and Enhancement Act*. The use of water from a water body or the diversion of water will require an approval under the *Water Act*.

Ontario
The construction and operation of generation facilities is governed by the *Environmental Assessment Act* ("**EAA**") and the *Environmental Protection Act* ("**EPA**"). It may also be necessary to obtain a permit or authorisation under the *Endangered Species Act, 2007*.

Non-renewable generation facilities must undertake an environmental assessment under the EAA and *Ontario Regulation 116/01: Electricity Projects*. Depending on the type and size of the facility, it may be necessary to undertake a full environmental assessment under the EAA or a more limited environmental screening report. In addition to completing an environmental assessment, it will be necessary to obtain specific environmental compliance approvals under the EPA. For example, a gas-fired generation facility will require an environmental compliance approval for air and noise emissions.

To construct and operate a renewable generation facility, a proponent must obtain a renewable energy approval under the EPA. The renewable energy approval regime is intended as a "one-window" approach that eliminates the need to undertake an environmental assessment and obtain separate environmental compliance approvals.

4.2 Terms and Conditions Imposed in Approvals to Construct and Operate Generation Facilities

Regulators and governmental agencies generally have the authority to impose conditions in approvals that are intended to reasonably mitigate potential adverse effects on the environment, including, air, water, land, wildlife, aquatic life; and the potential effects on people, including land use and disturbance, socioeconomic impacts, visual, noise, safety and use of the environment. Related to mitigation of adverse effects, regulators and agencies normally have the authority to prescribe conditions pertaining to construction methods, equipment to be used, reclamation and maintenance. Proponents are also required to comply with all applicable laws and technical codes and standards.

4.3 Proponent's Eminent Domain, Condemnation or Expropriation Rights

In some provinces where the use of public land (Crown land) is needed, land use authorisations may be obtained from the provincial government. Where a generating facility is proposed to be built on private land, the proponent may negotiate a lease or land purchase with the landowner. In some provinces, the legislation enables a proponent to expropriate land. The forced taking of land typically carries with it the obligation of the proponent to compensate the landowner based on the fair market value of the land and potentially other factors.

4.4 Requirements for Decommissioning

Applicable environmental laws and regulatory policy in each province govern the requirements for decommissioning power plants. For example, in Alberta an approval from the AUC is required to discontinue operations of a power plant. Pursuant to the *Environmental Protection and Enhancement Act*, a remediation certificate must be obtained from Alberta Environment and Parks ("**AEP**") to abandon, remediate and reclaim the site of a power plant. AEP may also require applicants for remediation certificates to provide financial or other security or insurance in respect of the remediation certificate. The terms and conditions of approvals or other orders from AEP frequently identify methods or parameters for carrying out remediation activities. There are no specific obligations in Alberta to fund decommissioning or reclamation activities over the physical life of the power plant.

5. Transmission

5.1 Regulation of Construction and Operation of Transmission Lines and Associated Facilities

5.1.1 Regulatory Process for Obtaining All Approvals to Construct and Operate Transmission Facilities

Federal Jurisdiction

Construction and operation of international transmission lines and designated transmission lines that will cross provincial boundaries require approval of the National Energy Board, under the *National Energy Board Act.* Transmission lines that have a voltage equal or greater than 345 kV or require 75 or more kilometres of right of way are considered a "designated project"under the *Canadian Environmental Assessment Act, 2012* and require an environmental assessment.

Provinces That Have a Vertically Integrated Utility Structure

The legislative and regulatory requirements to construct and operate provincial transmission facilities vary between provinces. Approvals may be required from the provincial electric utility regulator, along with approvals from the applicable environmental ministry. Depending on the scale of a project, approval by the provincial cabinet or a provincial minister may be required. In some jurisdictions, the regulator may conduct public hearings or proceedings to consider applications before issuing approvals.

Alberta

The *Hydro and Electric Energy Act* governs the construction and operation of transmission lines and associated facilities. Alberta employs a two-part approval process for the construction and operation of a transmission line and associated facilities. When the AESO, as the transmission system planner, determines that there is a need to construct a transmission line, it must prepare a needs identification document ("IN**ID"**) and file it with the AUC for approval of the need for the proposed project. The transmission utility that will be responsible to construct and operate the transmission line must file an application with the AUC for approval of the facilities proposed by the AESO in the NID. The NID and transmission facility applications can be considered by the AUC concurrently or sequentially.

Transmission lines that will cross private lands are often considered by the AUC in a public hearing to address matters such a routing, pole or tower design and locations, the effect of poles or towers on land use, visual impacts of the transmission line, and safety. The AUC endeavours to issue its decision within three months of concluding a hearing process.

Ontario
Under the *OEB Act*, transmission lines are defined as power lines operating at above 50kV. Construction of intra-provincial transmission lines greater than 2 km in length require a leave to construct approval from the OEB. The connection of new transmission facilities to the provincial transmission grid also requires the IESO to undertake a system impact assessment to consider any reliability implications. Lastly, transmission lines that are 115 kV or higher and more than 2 km in length require assessment under the *Environmental Assessment Act*,R.S.O. 1990, c. E.18. The level of the environmental assessment depends on the voltage and length of the proposed line.

OEB leave to construct under the *OEB Act* is the principal approval required to construct a transmission line greater than 2 km in length. The OEB applies a public interest test under which the OEB considers the interests of consumers with respect to prices and the reliability and quality of electricity service, including whether the proposed transmission facility is needed and whether it is preferable to other alternatives to satisfy the same need. Several years ago, the *OEB Act* was amended to provide the government with authority to designate priority transmission projects and to designate proponents to develop priority transmission projects. Priority designation relieves the proponent of the obligation to prove need in order to obtain leave to construct approval. Under the *Environmental Assessment Act*, projects may be subject to a class-type environmental screening or a full individual environmental assessment. Transmission lines that are higher voltage and of greater length require full individual environmental assessments.

5.1.2 Terms and Conditions Imposed in Approvals to Construct and Operate Transmission Facilities

Regulators and governmental agencies generally have the authority to impose conditions in approvals that are intended to reasonably mitigate potential adverse effects on the environment and potential effects on people, including land use and disturbance, visual, and safety. Related to mitigation of adverse effects, regulators normally have the authority to prescribe conditions pertaining to the construction methods and right-of-way maintenance. Proponents are also required to comply with all applicable laws and technical codes and standards.

5.1.3 Proponent's Eminent Domain, Condemnation or Expropriation Rights

Each province has its own regime to enable a proponent to obtain access to land to construct, operate and maintain transmission facilities. In some provinces, where the use of public land (Crown land) is needed, land use authorisations may be obtained from the provincial government. Where a transmission line is proposed to cross private land, the proponent may negotiate a transmission line right-of-way agreement with the landowner, or, failing that, the legislation in several provinces enables a proponent to expropriate land or obtain a right of entry order. The forced taking of land typically carries with it the obligation of the proponent to compensate the landowner for the fair market value of the affected land and, in addition to that for right of entry orders, the value of the loss of land use (i.e. reduced agricultural operations), adverse effect on the remaining land, and any damage to land.

5.1.4 Transmission Service Monopoly Rights

Vertically integrated electric utilities normally have monopoly rights to provide all utility services in the particular province, including transmission service required to deliver electricity for sale at the distribution level.

Alberta
In Alberta, there are no specified transmission service territories. However, and with certain exceptions, legislation requires the AESO to determine which transmission utility is eligible to apply to the AUC for approval to construct and operate a transmission facility based on the utility's historical transmission operations within a distribution service area established pursuant to the *Hydro and Electric Energy Act*. For example, ATCO Electric's transmission business unit has historically operated within the service area established for ATCO Electric's distribution business unit.

Ontario
In Ontario, OEB transmission licences provide transmitters with the exclusive right to provide transmission services within their service territory. HONI owns and operates approximately 98% of the provincial transmission grid. There are several other small licensed transmitters. Recently, there have been government policy initiatives to encourage new entrants and competition in the transmission sector.

5.2 Regulation of Transmission Service, Charges and Terms of Service

5.2.1 Establishment of Transmission Charges and Terms of Service

Provinces That Have a Vertically Integrated Utility Structure
In the provinces that have vertically integrated utilities, the costs approved by the regulator for transmission service are bundled with the costs approved for generation and distribution service to derive the bundled electricity rates paid by consumers.

Generally, utility rates are set using the traditional cost of service methodology to calculate a utility's revenue requirement that is recovered through approved rates. The revenue requirement includes the return on equity, cost of debt, depreciation expense, taxes and operating and maintenance costs.

Some provinces have a public review process by the provincial utility regulator, which may involve public hearings, with a process for written interrogatories, the filing of written evidence, cross-examination of other parties' witnesses in an oral hearing and the presentation of arguments. If appeals of a regulator's decisions are permitted, it is usually specified in the regulator's governing legislation.

Alberta

The *Electric Utilities Act* governs the provision of transmission service and the regulation of transmission rates and terms and conditions of service. The AUC has the responsibility to set just and reasonable rates and terms and conditions (the tariff) in respect of regulated utility service. Consistent with general rate-making principles applied widely in North America, a tariff approved by the AUC must not be unduly preferential, arbitrary or unjustly discriminatory.

Pursuant to the *Electric Utilities Act*, the AESO is responsible for providing "system access service" on the transmission system through the use of the transmission facilities of all transmission facility owners ("**TFOs**"). The AESO is required to apply to the AUC for approval of the AESO's tariff, which includes the rates charged for each class of system access service and the terms and conditions. The rates charged by the AESO are intended to recover the annual forecast amounts to be paid by the AESO to the TFOs for use of their transmission facilities, the AESO's own administrative costs, the cost of transmission line losses, and the cost of ancillary services obtained by the AESO.

The annual amount the AESO pays each TFO is based on the TFO's annual revenue requirement approved by the AUC on a forecast basis. The rate base of each TFO is set on the basis of historic capital cost, plus capital additions, less depreciation. The typical debt to equity capital structure for the rate base and the return on equity rates for TFOs are set in a generic cost of capital proceeding at regular intervals.

TFO revenue requirement applications are considered by the AUC in a public hearing process involving written interrogatories to the TFO, intervener evidence, interrogatories regarding intervener evidence, written reply evidence from the TFO, cross-examination of each party's witnesses at the hearing, written arguments and written reply arguments. The AUC endeavours to issue its decision within three months of the completion of arguments.

Comprehensive AESO tariff applications filed every three years follow a similar process.

Appeals of AUC decisions may be made to the Alberta Court of Appeal with permission from the Court on questions of law or jurisdiction. The *Alberta Utilities Commission Act* also permits AUC decisions to be reviewed by a review panel, for which the AUC has established threshold criteria.

Ontario

The *Ontario Energy Board Act* governs the provision of transmission service and the regulation of transmission rates and terms and conditions of service. The OEB has the responsibility to set just and reasonable rates and term and conditions (the tariff) in respect of regulated utility service. Transmission rates are intended to recover a transmitter's forecast revenue requirement, including a return on capital. Consistent with general rate-making principles applied widely in North America, a tariff approved by the OEB must not be unduly preferential, arbitrary or unjustly discriminatory.

Regulated transmitters' revenue requirement applications are considered by the OEB in a public hearing process involving written interrogatories to the transmitter, intervener evidence, interrogatories regarding intervener evidence, written reply evidence from the transmitter, cross-examination of each party's witnesses at the hearing, written arguments and written reply arguments. The OEB endeavours to issue its decision within approximately six months of the completion of arguments.

Appeals of OEB decisions may be made to the Ontario Divisional Court on questions of law or jurisdiction, and with leave from the Ontario Divisional Court to the Ontario Court of Appeal. Transmitters or others who are the subject of OEB decisions may, before exercising appeal rights, seek reconsideration by the OEB.

5.2.2 Open Access Transmission Service

British Columbia, Saskatchewan, Manitoba, Québec, New Brunswick and Nova Scotia each have a form of an Open Access Transmission Tariff ("**OATT**"), which is modelled after the United States' Federal Energy Regulatory Commission OATT. The purpose of an OATT is to ensure that users of a transmission system are able to access service on an open, non-discriminatory and non-preferential basis. The electric utility in Prince Edward Island has applied to its regulator for approval of a form of an OATT. The legislature of Newfoundland and Labrador has passed a bill that is not yet law, which will require the provision of open, non-discriminatory and non-preferential access to, interconnection with and use of the transmission system.

Alberta
The AESO is statutorily obligated to provide system access service on the Alberta transmission system in a manner that provides all market participants wishing to exchange electric energy a reasonable opportunity to do so. There are no transmission rights in Alberta and access to the transmission system by market participants is open, non-discriminatory and non-preferential, pursuant to the terms of the AESO's tariff approved by the AUC.

Ontario
A fundamental principle upon which Ontario's restructured electricity market was premised was the principle of "open access" — i.e. the obligation by transmitters and distributors to provide generators, retailers and consumers with non-discriminatory access to their transmission and distribution system. This principle is embedded in the *Electricity Act*. This principle has, in part, been modified by amendments which provide that transmitters provide priority connection for renewable or other non-emitting resources.

6. Distribution

6.1 Regulation of Construction and Operation of Electric Distribution Facilities

6.1.1 Regulatory Process for Obtaining All Approvals to Construct and Operate Distribution Facilities

The construction and operation of distribution facilities in Canadian provinces is largely exempt from regulation by the provincial utilities regulator. Instead, the location, construction and operation of distribution facilities within municipal boundaries may be subject to approval of the municipality in which the distribution facilities are to be developed. In some provinces, such as Alberta, the right to provide utility service within the boundaries of a municipality is vested in the municipality. Some municipalities enter into franchise agreements with distribution utilities that grant them the right to construct and operate a distribution system within municipal boundaries.

6.1.2 Terms and Conditions Imposed in Approvals to Construct and Operate

To the extent that a regulatory approval is required to construct and operate distribution facilities, approving authorities generally have authority to require compliance with all applicable laws and technical codes and standards.6.1.3 Proponent's Eminent Domain, Condemnation or Expropriation Rights

Each province has its own regime to enable a proponent to obtain access to land to construct, operate and maintain distribution facilities. In some provinces, where the use of public land (Crown land) is needed, land use authorisations may be obtained from the provincial government. Where a distribution line is proposed to cross private land, the proponent may negotiate a right-of-way agreement with the landowner, or, failing that, the legislation in several provinces enables a proponent to expropriate land or obtain a right of entry order. The forced taking of land typically carries with it the obligation of the proponent to compensate the landowner for the fair market value of the affected land and, in addition to that for right of entry orders, the value of the loss of land use (i.e. reduced agricultural operations), adverse effect on the remaining land, and any damage to land.

Municipalities may grant access for the construction, operation and maintenance of distribution facilities to be located within their boundaries.

6.1.4 Distribution Service Monopoly Rights

Vertically integrated utilities generally have monopoly rights to provide utility services, including distribution service. In Alberta, distribution utilities have monopoly rights to provide service within a service area prescribed by the AUC, pursuant to the *Hydro and Electric Energy Act*. In Ontario, no person may own or operate an electric distribution system unless licensed to do so by the OEB. Distribution licences granted by the OEB provide distributors with the right to provide services within their service territory, which in practice is an exclusive right.

6.2 Regulation of Distribution Service, Charges and Terms of Service

6.2.1 Establishment of Distribution Charges and Terms of Service

Generally, in the provinces that have vertically integrated utilities, the costs approved by the regulator for distribution service are bundled with the costs approved for generation and transmission service to derive the approved bundled electricity rates paid by consumers.

Except where a provincial regulator has adopted a different approach to the regulation of distribution service rates, such as performance-based regulation, the traditional cost of service methodology is generally applied to calculate the distribution portion of the utility's revenue requirement for recovery through approved rates charged to consumers. The revenue requirement includes the return on equity, cost of debt, depreciation expense, taxes and operating and maintenance costs.

Some provinces have a public review process by the provincial utility regulator, which may involve public hearings, with a process for written interrogatories, the filing of written evidence, cross-examination of other parties' witnesses in an oral hearing and the presentation of arguments. If appeals of a regulator's decisions are permitted, it is usually specified in the regulator's governing legislation.

Alberta

Pursuant to the *Electric Utilities Act*, the AUC has the responsibility to set just and reasonable rates and term and conditions (the tariff) in respect of regulated utility service. Consistent with general rate-making principles applied widely in North America, a tariff approved by the AUC must not be unduly preferential, arbitrary or unjustly discriminatory.

The deemed debt to equity capital structure for rate base and the rate of return on equity for distribution utilities are set in a generic cost of capital proceeding at regular intervals. The AUC has adopted a form of performance-based regulation ("**PBR**") to set rates for distribution utilities, rather than the traditional cost of service methodology, in order to mimic competition, create incentives for the utility to reduce costs through efficiency, and thereby keep distribution service rates lower than might otherwise be the case. Alberta has five-year PBR terms.

The PBR framework approved by the AUC provides a formulaic rate-setting mechanism that adjusts rates annually due to an inflation indexing mechanism, less a productivity offset. A distribution utility may apply for approval to recover specific costs if they cannot be recovered under the "inflation less productivity" mechanism, and subject to the satisfaction of certain other criteria. The AUC also applies a "capital tracker" mechanism to fund certain capital-related costs.

The AUC typically conducts a public hearing process each time it resets the five-year PBR plans for distribution utilities and when it considers capital tracker applications that may result in the adjustment of rates resulting from approved PBR plans. The hearing process can involve written interrogatories to the utility, intervener evidence, interrogatories regarding intervener evidence, written reply evidence from the utility, cross-examination of each party's witnesses at the hearing, written arguments and written reply arguments. The AUC endeavours to issue its decision within three months of the completion of arguments.

Appeals of AUC decisions may be made to the Alberta Court of Appeal with permission from the Court on questions of law or jurisdiction. The *Alberta Utilities Commission Act* also permits AUC decisions to be reviewed by an AUC review panel, for which the AUC has established threshold criteria.

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