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CANADA

LAW AND PRACTICE:

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Law and Practice

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1. General Structure of Petroleum Ownership and Regulation

1.1 System of Petroleum Ownership

Petroleum ownership refers to one's legal possession of petroleum from under a parcel of land, as well as the right to win, work and recover it. In Canada, certain of these rights are owned by the federal government, but the majority are owned by the provinces (referred to as the "**Crown**"), which, as a result, have jurisdiction over the development of onshore oil and natural gas resources within their provincial boundaries. Under the *Constitution Act* (1867), the original provinces of Canada retained ownership of the petroleum resources within their boundaries. When British Columbia and Prince Edward Island later joined the confederation, they were treated similarly and allowed to retain ownership of the petroleum resources within their boundaries. However, the three prairie provinces (Manitoba, Alberta and Saskatchewan) did not receive ownership of the mineral resources underlying their lands until 1930, with the enactment of the *Natural Resources Transfer Act*, following a contentious and protracted debate.

Petroleum resources may also be held privately. For example, in Alberta, approximately 81% of the petroleum resources are owned by the Alberta Crown, while the balance is privately owned. Privately owned petroleum resources are sometimes referred to as freehold lands.

The federal government owns the petroleum resources that are located in offshore waters, on the continental shelf and under lands onshore that are owned by the federal government. The federal government also retains ownership of petroleum rights in some federally administered onshore lands (for example, the northern territories of Nunavut and the Northwest Territories), and on behalf of Canada's Aboriginal peoples with unsettled land claims. For those few settled land claims, ownership of petroleum rights lies with the Aboriginal governments holding tenure over them.

The provinces of Nova Scotia and Newfoundland and Labrador, Canada's most easterly provinces, have entered into accords with the federal government, providing for the joint regulation and revenue sharing of the petroleum resources located offshore those provinces. The Atlantic Accords, as the governing legislation is sometimes known, arose after the province of Newfoundland's argument that it owned the offshore mineral resources was defeated in the Supreme Court of Canada. Following some political maneuvering, the then newly-elected federal government granted significant decision-making powers and revenue sharing rights to the province of Newfoundland and Labrador in relation to the offshore petroleum rights. Similar arrangements were agreed between the federal government and the province of Nova Scotia. Both regimes are now implemented and managed jointly by the federal and applicable provincial governments.

Under all of the ownership regimes referred to above, the owners (being the provincial Crowns, joint federal/provincial bodies and private owners) may issue rights to private investors to explore for, produce and take petroleum substances from their respective lands.

The federal government shares responsibility with the provinces for environmental protection and conservation, and for energy trading and transportation.

1.2 Regulatory Bodies

Both the federal and provincial governments regulate petroleum activities in Canada. The National Energy Board ("**NEB**") is responsible for regulating major oil and gas projects that fall under federal jurisdiction (eg, offshore oilfield projects and pipelines that cross provincial or national borders), pursuant to the *National Energy Board Act*. Additionally, both the NEB and the Canadian Environmental Assessment Agency oversee environmental aspects of certain energy developments, pursuant to the *Canadian Environmental Assessment Act, 2012*.

Accords negotiated between the federal government and each of the provinces of Nova Scotia and Newfoundland and Labrador establish joint administration agencies for offshore developments, called the Canada-Nova Scotia Offshore Petroleum Board and the Canada-Newfoundland and Labrador Offshore Petroleum Board, respectively.

Except for developments on federal lands, the provinces are responsible for regulating oil and gas projects located within their borders, including resource development, intra-provincial pipeline and gathering systems, and facilities such as refineries, bitumen upgraders, or gas processing plants. Each province has a slightly different structure, with government ministries and/or administrative tribunals being responsible for the oversight of petroleum resources, including such matters as conservation and environmental protection. In some cases, provincial and federal oversight overlaps, meaning that certain projects will be subject to both regimes. In those cases, projects may be subject to joint federal-provincial reviews.

In Alberta, the Alberta Energy Regulator ("**AER**") provides a one-window system whereby project proponents can obtain both operating and environmental permits for their petroleum activities. A similar system is in place in British Columbia, where operational permits can be obtained from the British Columbia Oil and Gas Commission.

1.3 National Oil or Gas Company

Canada does not have a national oil and gas company.

1.4 Principal Petroleum Law(s) and Regulations

Each of the federal, provincial and territorial governments has jurisdiction over various aspects involving the granting of upstream licences and the conduct of upstream operations. Accordingly, they each have a legislative regime to deal with tenure, operations, the transportation of petroleum and protection of the environment.

The key federal legislation includes the following:

- **Canadian Petroleum Resources Act**: This act provides the framework for the granting of rights to explore and develop petroleum on federal lands, including the royalty regime.
- **National Energy Board Act**: This act provides the regulatory regime for pipelines crossing provincial or international borders, including the approvals required for those kinds of projects, and the applicable tolls and tariffs for them, and for the import and export of oil, natural gas, natural gas liquids and electricity.
- **Canadian Environmental Assessment Act, 2012**: This act establishes the federal practices for environmental assessments, including reviews of regulated projects, consultation with Aboriginal groups and co-operation with provinces, where required.
- **Canadian Environmental Protection Act**: This act deals with pollution prevention, risk assessments, the handling of toxic substances and other environmental management processes.
- **Indian Oil and Gas Act**: This act provides the regulatory framework for managing oil and gas exploration and development on certain First Nations lands.

Similar legislation exists for each province and territory of Canada. In addition, certain provinces have legislation dealing with upstream operations that are unique to that jurisdiction, such as for:

- the oil sands in the provinces of Alberta and Saskatchewan;
- joint offshore petroleum exploration and development with the federal government in the provinces of Nova Scotia and Newfoundland and Labrador; and
- the export of liquefied natural gas ("**LNG**") in the province of British Columbia.

2. Private Investment in Petroleum - Upstream

2.1 Forms of Allowed Private Investment in Upstream Interests

The forms of direct investment by private investors in upstream interests include the following:

Crown Owned Onshore Petroleum

To explore for and develop onshore petroleum owned by a provincial Crown, a private investor must enter into a petroleum and natural gas licence or lease, or an oil sands lease in a prescribed form with the applicable Crown (a "Crown Lease").

A Crown Lease typically:

- confers rights on the private investor to explore for, develop and produce those types of petroleum substances as are stipulated in the Crown Lease from the applicable lands for a specified term;
- allows for the continuation of the term where petroleum is being produced from the leased lands, or where there is a well on those lands capable of producing petroleum; and
- requires the payment of annual rentals and of royalties in respect of the petroleum produced from those lands.

In certain circumstances, the Crown has the authority to alter the terms and conditions of the rights granted under a Crown Lease through legislative action. Crown Leases contain a provision requiring lessees to comply with all applicable laws and regulations. That provision enables the Crown to make those kinds of alterations.

Privately Owned Petroleum

A private investor may negotiate the rights to explore for, develop and produce privately owned petroleum from the owner of the applicable freehold lands; such rights are typically granted in a lease between the private owner and the private investor (a "Freehold Lease"). These Freehold Leases are frequently based on industry standard forms developed by the Canadian Association of Petroleum Landmen, which contain similar provisions to Crown Leases, including a primary term, continuation of the term based on production, annual rentals and the payment of royalties in respect of the petroleum produced from the applicable freehold lands.

Offshore Petroleum

In order to explore for and develop offshore petroleum resources jointly administered by the federal government and either the province of Newfoundland and Labrador or the province of Nova Scotia, a private investor must obtain an exploration licence in respect of the proposed project. As discussed below, bids for licences to explore for and develop offshore petroleum include work commitments and substantial financial assurances in support of those work commitments. In these and other respects, the terms on which rights are granted to private investors to explore for and develop offshore petroleum are different from typical Crown Leases and Freehold Leases of onshore petroleum.

Private investors can also indirectly acquire existing upstream interests from the holders of those upstream interests, and can acquire entities that hold upstream licences through merger and acquisition transactions.

2.2 Issuing Upstream Licences

Crown Leases

The process to obtain most Crown Leases in Western Canada is to request the applicable Crown to post the lands for sale to the public. Private investors are then able to provide confidential bids for the posted land. The bidder who is prepared to pay the most per hectare for the posted land is generally awarded the rights to explore and develop those lands. No work commitments are required. The royalties payable on the petroleum that may be produced from those Crown lands is fixed by legislation. Once a private investor has acquired a Crown Lease, it must obtain operating licences to carry out upstream operations, including to drill a well or to build and operate gathering and processing facilities. In Alberta, British Columbia and Saskatchewan, the operator must satisfy certain financial thresholds in relation to the liabilities it will assume in conducting those upstream operations. Those financial threshold requirements aim to ensure that the operator has sufficient resources to properly abandon, remediate and reclaim the well or facility site. In addition, negotiations with the owner of the surface of the applicable lands for access to those lands may be required. However, if an arrangement is not reached between the owner of the surface rights and the lessee under the Crown Lease, application may be made to the applicable provincial surface rights board for the required rights of access. Orders granting those rights of access will be subject to compensation payments to be made to the surface rights owner.

Oil Sands

Alberta's oil sands are subject to a separate regulatory regime. Alberta Energy administers oil sands rights owned by the Alberta Crown. Those rights are granted to private investors by way of either a permit or an oil sands lease (the private investor may choose either). The terms of Crown oil sands permits and leases are prescribed by regulation, and are not subject to negotiation.

Freehold Leases

The terms of Freehold Leases are the subject of negotiations between the private owner of the petroleum and the private investor.

Offshore Petroleum

Exploration licences for projects in the areas offshore of Nova Scotia and Newfoundland and Labrador are issued through a public bidding process that requires successful bidders to make work commitments and post security for the upstream operations that they agree to undertake. This bidding process is described in greater detail below. The terms of a production licence are the subject of negotiation with the respective federal and provincial joint administration agency, and are discussed with other key terms of upstream licences below.

First Nations Lands

Leases for lands governed by the Indian Oil and Gas Act may be granted:

- following a public call for tenders where a lease is granted without work commitments;
- after a call for proposals;
- as a result of a competitive bidding process that includes work commitments; or
- after direct negotiations with the applicable First Nations group.

Upstream operations on First Nations lands are generally subject to the exploration, development and production regulations of the province in which the First Nations lands are situated. In addition, the applicable First Nations group must approve any surface access arrangements.

2.3 Typical Fiscal Terms Under Upstream Licences

In Canada, each province implements its own regime with respect to charging and collecting royalties from oil and gas production. The royalty regimes of Alberta, British Columbia, Saskatchewan and Newfoundland and Labrador offshore area are discussed below.

Alberta

Prior to 1 January, 2017, royalties were structured and calculated differently depending on the type of resource (natural gas, conventional oil, or oil sands). Royalties on the production of conventional oil and natural gas were calculated based on a sliding-scale formula that considered a number of factors, including the quantity of production and the price received for that petroleum. On this basis, royalty rates payable on conventional oil wells ranged from 0% to 40%, while the royalty rates payable for natural gas wells ranged from 5% to 36%.

On January 1, 2017, Alberta's Modernized Royalty Framework ("MRF") came into effect. For all conventional oil and natural gas wells drilled prior to this date, the above noted existing royalty regime continues to apply until 1 January, 2027, at which time it will convert to the MRF.

For all conventional oil, liquids and natural gas wells drilled after 1 January, 2017, the MRF provides for a harmonisation of the royalty framework. The MRF emulates a revenue-minus-cost royalty structure that is consistent with global standards for the pre-payout/post-payout models of risk and profit sharing. The new harmonised royalty formula is based on several factors, including average industry drilling costs rather than the actual costs of the applicable well or project. Lessees will pay a flat royalty of 5% on a well's early production until the well's total revenue from all petroleum products produced equals "C*" (the average industry drilling costs). After that time, lessees will pay higher royalty rates, which vary depending on the type of petroleum, the quantity produced and market prices. Royalty rates will then decrease to match declining production rates once specific wells reach a "Maturity Threshold" (that occurs when monthly production from the well is below the equivalent of 194 cubic metres). As there is increased complexity and cost in drilling deep wells, for those wells with a true vertical depth greater than 2000 metres, the MRF provides an amended calculation of C*, resulting in decreased royalty rates compared to shallower wells.

Royalty rates for oil sands projects remain unchanged by the MRF, and depend on whether "payout" has been achieved. "Payout" for an oil sands project is the point in time at which the producer has recovered its major operating and capital costs and an allowable return on its investment. During the pre-payout period, royalties are payable based on a percentage of the producer's gross revenues, ranging from 1% to 9%, depending on the prices of oil. In the post-payout period, royalties are payable based on a percentage of the producer's gross revenues, ranging from 1% to 9%, or on a percentage of the producer's net revenues, ranging from 25% to 40%, whichever is higher, in each case depending on the prices of oil.

British Columbia

In British Columbia, royalties are structured and calculated differently for oil and natural gas. Oil royalty rates are calculated on a sliding-scale formula that is based on a number of factors, including quantity of production, the oil vintage (new, old, third tier or heavy), and, where the oil is third tier or heavy oil, the net price that the oil was sold for. On this basis, royalty rates for oil range from 0% to 40%.

Royalty rates for natural gas are calculated based on a number of factors, including quantity of production, the price received, the date the well was drilled, and whether the gas is "conservation gas" (solution gas produced in association with oil) or "non-conservation gas". For conservation gas wells, the royalty rates range from 8% to 27%. For non-conservation gas wells drilled before June 1, 1998, the royalty rates range from 15% to 27%. For non-conservation gas wells on lands acquired after June 1, 1998 which are completed within five years of the date Crown Leases were issued, the royalty rates range from 9% to 27%. In all other non-conservation gas wells, the royalty rates range from 12% to 27%.

All natural gas by-products have a fixed royalty rate, with a 20% rate for both liquefied petroleum gas and condensate, and a 16.667% rate for sulphur.

Producers of oil and natural gas may qualify for a number of credits and exemptions, thereby reducing the overall royalty rates. These include a natural gas deep well credit, a natural gas deep well re-entry credit, infrastructure credits, discovery well exemptions and an exemption for natural gas or by-products used for production, drilling or injection. Furthermore, royalty rate reductions are offered on low and marginal productivity gas wells.

Saskatchewan

Oil and natural gas royalty rates are calculated on a sliding-scale formula based on the location of the well, commodity prices, the quantity of production and the date the well was drilled. For wells drilled after October 1, 2002, royalty rates can range from 0% to 35%, depending on the foregoing factors.

Saskatchewan also has a number of volume-based drilling incentives for oil and natural gas produced from:

- deep development vertical oil wells (vertical depth greater than 1700 metres) drilled after October 1, 2002;
- exploratory vertical oil wells (drilled at least 3 kilometres away from the nearest oil well) drilled after October 1, 2002;
- horizontal oil wells drilled after October 1, 2002;
- incremental oil produced from waterflood projects commenced after October 1, 2002;
- exploratory gas wells drilled after October 1, 2002; and
- horizontal gas wells drilled between June 1, 2010 and March 31, 2013.

Newfoundland and Labrador Offshore Area

Royalty rates for offshore oil projects in Newfoundland and Labrador have historically varied from project to project. However, on November 2, 2015 Newfoundland and Labrador introduced a new generic offshore oil royalty regime comprised of a basic and net royalty, both of which are linked to cost recovery and profitability, as measured by an "R Factor". The basic royalty, which is applied to gross revenue, begins at first production and can range from 1% to 7.5%, depending on commodity prices as the project recovers its costs. The net royalty, which is applied to the net revenue, only begins once project costs are fully recovered and ranges from 10% to 50%, depending on commodity prices. The basic royalty becomes a credit against the net royalty once payable.

2.4 Income or Profits Tax Regime Applicable to Upstream Operations

Under the *Income Tax Act* (Canada) and the regulations thereunder (the "Tax Act"), corporations that are resident in Canada are taxed on their worldwide income. Whether a corporation is resident in Canada is a question of fact, but a corporation is generally considered to be resident in Canada for income tax purposes if its central management and control is exercised in Canada. Furthermore, a corporation is deemed by the Tax Act to be resident in Canada if it was incorporated or continued into Canada. In general, the federal income tax rate for corporations for the 2016 taxation year was 15%.

Non-resident corporations are subject to Canadian income tax on a business carried on in Canada, including upstream oil and gas activities, and on taxable capital gains from the disposition of "taxable Canadian property", which is defined in the Tax Act to include real property situated in Canada and Canadian resource property. Canadian resource property includes a right, licence or privilege to explore, drill or produce petroleum or natural gas in Canada. Under the common law principles, a person is generally considered to carry on business in Canada if they conclude contracts in Canada or if the operations from which profits arise are located in Canada.

Canadian tax treaties generally follow the OECD Model Tax Convention on Income and Capital. Under Canada's tax treaties, business profits are generally only taxable in Canada to the extent that the non-resident has a "permanent establishment" in Canada. A permanent establishment generally means a fixed place of business in Canada through which the business of the entity is wholly or partially carried on. Under the Canada-US Income Tax Convention, for example, the term "permanent establishment" includes a place of management, branch, office, factory or workshop, and a mine, oil or gas well, a quarry, or any other place of extraction of natural resources. Generally, tax treaties also provide that if a non-resident person carries on business in Canada through an agent, the non-resident has a permanent establishment in Canada if the agent habitually exercises authority to execute contracts for the non-resident entity.

Partnerships are generally not treated as persons under the Tax Act ut instead are a flow-through entity, such that the income (or loss) of a partnership is allocated to the partners, to be included as part of their taxable income.

Provincial/territorial income taxes will generally be payable by a corporation on taxable income earned in a province or territory where the corporation carries on business through a permanent establishment in that province. For this purpose, a permanent establishment can be an office, a branch or an oil well or territory. Provincial/territorial corporate income tax rates for 2016 ranged from 11% to 16%. In the event that the non-resident corporation's income is not earned in a province/territory, an increased federal income tax rate applies, which was 25% in 2016.

As discussed under **2.3 Typical Fiscal Terms Under Upstream Licences**, various provinces and territories impose royalties on oil and gas production. Crown royalty rates vary by province/territory and are calculated based generally on the quantity and the type of resource. In general terms, payments to the Crown for those royalties are deductible in computing a taxpayer's taxable income for income tax purposes.

Canada's Tax Act allows certain expenses to be deducted from income, to the extent those expenses are reasonable, and are incurred for the purpose of earning income from a business. Certain expenses incurred in upstream operations are provided special resource expense deductions, depending on the nature of the expense. These intangible expenditures are generally added to certain cumulative pools, classified as either:

- cumulative Canadian exploration expenses ("CEE");
- cumulative Canadian development expenses ("CDE"); or
- cumulative Canadian oil and gas property expenses ("COGPE").

In certain circumstances, successor rules can limit the deductibility of those pools to income from particular resource properties, such as following the acquisition of control of a resource corporation.

Expenses associated with the exploration of oil and gas deposits are generally included in CEE. The most common types of expenses that fall into CEE include seismic expenses for a deposit not previously known to exist, expenses incurred for drilling or completing an exploration well that results in a new discovery, expenses incurred on a well that has not produced within 24 months of completion, and wells that result in costs of more than CAD5 million to complete. CEE is typically the most favourable of the special resource expense deductions, as a corporation can claim a deduction of 100% of its cumulative CEE in a taxation year. A corporation whose principal business is the exploration of or drilling for oil and natural gas can only deduct CEE to the extent of its income, and cannot use its CEE deductions to create a loss.

Expenses associated with the development of oil and gas properties are generally included in CDE. Costs associated with most drilling activities to develop an oil and gas well, a disposal well or injection wells, for monitoring wells, and for preparing a site for production or recompletion of a well after production commences, and which are not CEE, are added to CDE in the year incurred. A corporation can claim a deduction of up to 30% of its cumulative CDE in a taxation year on a declining-balance basis.

Expenses incurred in a taxation year to acquire "Canadian resource property", including oil and gas wells, rights to explore for oil and gas, and rights to royalties, are added to a corporation's COGPE balance. A corporation can claim a deduction of up to 10% of its cumulative COGPE in a taxation year on a declining-balance basis.

The capital cost associated with the acquisition and disposition of oil and gas equipment and other tangible property in the course of resource exploration is categorised as depreciable property, and is treated under the Tax Act's capital cost allowance ("**CCA**") system. The Tax Act sets out prescribed rates to allow for discretionary deductions for depreciable capital property in a given taxation year. Most tangible assets related to upstream operations are categorised as "Class 41" assets, and the capital costs of Class 41 assets are deducted at a rate of 25% on a declining-balance basis.

In order to enable corporations in the resource sector – particularly junior exploration companies – to attract equity investment to fund exploration and drilling programmes in Canada, the Tax Act allows for 'flow-through shares' ("**FTS**") to be issued in certain circumstances. The FTS mechanism allows a principal-business corporation (which includes a corporation whose principal business is the production, refining, marketing, exploring or drilling of petroleum or natural gas) to incur and renounce certain eligible expenses (generally CDE and CEE) to a shareholder in an amount up to the consideration paid by the shareholder for the FTS shares, all pursuant to an FTS agreement. This CDE or CEE is then deductible, at the above-noted rates, against the shareholder's taxable income.

As part of its 2015 federal election platform, the federal government announced its intention to reduce fossil fuel subsidies and that, as a first step in achieving that goal, the availability of CEE deductions would be limited to cases of unsuccessful exploration. After the election, the Prime Minister of Canada directed the Minister of Finance (Canada) in a mandate letter that one of his "top priorities" should be to "develop proposals to allow a Canadian Exploration Expenses tax deduction only in cases of unsuccessful exploration and re-direct any savings to investments in new and clean technologies". It is unclear whether the proposed changes will affect CEE incurred in the course of exploration. The extent and timing of the impact on the FTS regime in the Tax Act is also unclear. Specific tax proposals were not introduced with the 2016 Federal Budget released by the Minister of Finance (Canada) on March 22, 2016, and have not been subsequently introduced.

The *Excise Tax Act* (Canada) ("ETA") imposes a comprehensive federal goods and services tax ("GST") generally applicable to the supply of goods and services made in, or imported into, Canada. The rate of the tax is currently 5%, and applies at each stage of production. However, if the purchaser of goods or services is involved in a commercial activity and is a qualified GST registrant, it will generally be entitled to claim a refund, called an "input tax credit", for GST paid.

Pursuant to the ETA, a business, whether resident or non-resident, will normally be required to charge and collect GST from its customers on taxable goods and services supplied by it in Canada in the course of any business carried on in Canada. Businesses that make taxable supplies in the course of any business carried on in Canada must also become GST registrants, unless they are "small suppliers" (generally very small businesses making less than CAD30,000 in taxable supplies in a 12-month period). GST registrants are required to file yearly, quarterly or monthly returns, depending on the registrants' annual sales.

The provinces of Nova Scotia, New Brunswick, Newfoundland, Ontario and Prince Edward Island have harmonised their provincial sales taxes with the GST to form a single Harmonized Sales Tax ("**HST**"), which is also imposed under the ETA, and has essentially the same rules as the GST. The HST includes both a provincial component and the federal GST for a combined rate of 13% in Ontario and 15% in Nova Scotia, New Brunswick, Newfoundland and Prince Edward Island (depending on where the supply is made).

Quebec levies the Quebec Sales Tax ("**QST**"), which is applied and administered separate from the GST regime but is now harmonised with it. The 9.975% QST is a tax on the consumption of goods and services in Quebec. Saskatchewan, British Columbia and Manitoba each impose a provincial sales tax or retail sales tax ("**PST**"). Each separate PST has distinct but similar rules. The rates for these taxes are 5% in Saskatchewan, 7% in British Columbia and 8% in Manitoba. While certain exemptions do apply, these taxes must generally be collected and remitted by the vendor of the property or services. Alberta does not impose a provincial sales tax at this time.

2.5 Special Rights for National Oil or Gas Companies

Canada does not have a national oil and gas company.

2.6 Local Content Requirements Applicable to Upstream Operations

The Canadian federal government and provincial governments seek to attract investment into capital-intensive upstream operations, so Crown Leases or other upstream licences do not typically contain requirements for the use of local goods or services, or to employ local labour.

However, the legislation governing the offshore areas of Nova Scotia and Newfoundland and Labrador does set forth certain requirements and preferences for local contractors and employees. Residents of the applicable province must be given first consideration for training and employment.

Preference must also be given to services performed and goods manufactured in the province where those goods and services are competitive in terms of price and quality.

For acquisitions by foreign investors above certain thresholds that require approval by the federal government under the *Investment Canada Act* ("**ICA**"), a foreign investor may be required to make undertakings regarding the retention of Canadian employees and senior staff, as well as the future conduct of the business, as discussed below under **4.1 Foreign Investment Rules Applicable to Investments in Petroleum**. Undertakings also typically require the foreign investor to purchase Canadian goods and services, where those goods and services are of equal or better quality and on terms and conditions at least equal to those offered by non-Canadian suppliers (in other words, to buy Canadian in the event of a tie).

In addition, many project proponents negotiate benefit agreements with local Aboriginal groups. Where the Crown is requested to issue regulatory and environmental approvals for a petroleum resource project that is anticipated to adversely affect potential or established Aboriginal or treaty rights, the Crown must consult with the Aboriginal groups that will be affected by that decision before making its decision. Project proponents will often negotiate benefits agreements with Aboriginal groups in the course of seeking those approvals. While these benefit agreements are negotiated privately, they generally provide that the Aboriginal group will support the proponent's proposed project in the regulatory approval processes, in exchange for which the proponent guarantees certain benefits, which may include preferential hiring, training, business opportunities, environmental monitoring, and funding for local social programmes and infrastructure.

2.7 Requirements of Licence Holder to Proceed to Development and Production

Alberta

Once a lease for the exploration and production of petroleum on Crown lands has been issued by the Alberta Crown, no further application or approval is required to proceed from commercial discovery to production. Typically, the same approach applies to Freehold Leases.

In Alberta, a Crown lease for the exploration and production of petroleum substances will automatically continue past the expiry of its five-year term if the lands, or a portion of the lands, subject to that mineral lease are proven to be productive. A lease is proven to be productive by the drilling of a well, producing petroleum substances, mapping, being part of a unit agreement or by paying offset compensation, where applicable. If a lease is proven productive, it will continue indefinitely until the interest holder can no longer demonstrate that the lands that are subject to the lease are capable of production, or until the lease is surrendered or terminated by reason of default.

Oil sands rights may be issued by permit or by primary lease. A permit is issued for a five-year term and may be converted into an oil sands lease through a process called "lease selection", in which technical data is submitted to the Department of Energy to support an application that the oil sands subject to the permit are productive. If approved, the interest holder will be granted a primary lease (15-year term).

However, before an interest holder may begin construction of an oil sands project, it must undertake an extensive stakeholder consultation process and seek further approval from the Alberta Energy Regulator. The project approval process will involve a review of the entire project, including potential environmental impacts, and may involve a joint federal and provincial review by the Canadian Environmental Assessment Agency.

At the end of its 15-year term, a primary lease may be continued as a "continued lease". The extent to which the interest holder has evaluated the oil sands covered by the primary lease and whether the oil sands are producing will be evaluated by the Department of Energy in order to determine if the application will be granted. If continuation is granted, the lease will continue indefinitely, subject to the lessee's compliance with the lease terms and applicable legislation.

British Columbia

In British Columbia, a party may be issued a permit, a drilling licence or a lease in relation to Crown petroleum substances. To convert a drilling licence to a lease, a qualified earning well must be drilled. Permits (one-year term) and drilling licences (three-, four- or five-year term) allow the interest holder to conduct exploratory drilling, but do not grant the right to produce petroleum substances. Leases, on the other hand, do grant the interest holder the right to produce petroleum substances. Leases may be granted directly from the Crown or issued from a permit on application to the Crown for an initial term of five or ten years, depending on the location of the lands, but may also be continued past the initial term on application to the Crown.

Saskatchewan

In Saskatchewan, the Crown may issue an exploration licence, which grants the holder the right to drill for, produce and sell oil and gas or oil sands within the lands described in the exploration licence. An exploration licence is issued for an initial term of two to five years, depending on the location of the lands. A licensee may apply to convert an exploration licence into a lease, which grants the holder thereof the right to extract, recover and produce petroleum substances, subject to the governing legislation.

Nova Scotia
The Canada-Nova Scotia Offshore Petroleum Board is tasked with managing and administering offshore Nova Scotia petroleum licences. There are three major licences that may be granted by the Board: exploration, significant discovery and production. If sufficient hydrocarbon reserves subject to an exploration or significant discovery licence have been discovered that will justify the investment of capital and the effort to bring the discovery to production (" **Commercial Discovery** "), the interest owner may then apply for a production licence. A production licence may contain any terms and conditions prescribed by the Board (unless they are inconsistent with the relevant legislation) and has a term of 25 years, but can be extended if the Board has reasonable grounds to believe that commercial production is continuing or, if ceased, will recommence. No production licence or share in a production licence may be held by any person unless that person is a corporation incorporated in Canada.

Newfoundland and Labrador
Licensing of offshore Newfoundland and Labrador petroleum resources is managed by the Canada–Newfoundland and Labrador Offshore Petroleum Board. As with the legislation governing offshore reserves in Nova Scotia, an interest holder is entitled to a production licence if there has been a declaration of Commercial Discovery. A production licence will be issued for a term of 25 years from its effective date or for such period thereafter during which commercial production continues or, if it ceased prior to the expiration date, will recommence.

2.8 Other Key Terms of Each Type of Upstream Licence
Onshore
The key terms of onshore upstream licences vary across jurisdictions. In addition, there are differences between Crown Leases and Freehold Leases. However, all of those upstream licences generally provide for a primary term allowing for an exploration phase and continuation of the term thereafter if the lands are found to be capable of producing petroleum. The primary terms for Crown Leases granting rights to conventional petroleum range from one to five years, depending on where the lands are located. The primary terms of Crown Leases for oil sands are 15 years. The primary term of a Freehold Lease is one of the terms that the owner of the freehold petroleum and the private investor will negotiate.

Annual rentals are payable throughout the term of Crown Leases, and either during the primary term only or throughout the term on Freehold Leases. In addition, royalties are payable to the owner of the freehold petroleum on the petroleum produced from the freehold lands.

Crown Leases that are considered to be capable of production are generally continued indefinitely. However, at the end of the primary term of that Crown Lease, either the rights below the deepest formation capable of production or all zones not capable of production will revert to the government and can be resold under a new Crown Lease. Freehold Leases typically require that the lessee produce the petroleum. The Freehold Lease may be terminated if production is suspended, unless the reason for the suspension is specifically permitted by the Freehold Lease.

Offshore
As discussed above, the offshore areas of the provinces of Nova Scotia and Newfoundland and Labrador fall under different licensing regimes. Exploration licences are publicly auctioned and generally have primary terms of five years. The bids for exploration licences will include minimum work commitments, security for those commitments, and a benefits plan. The development plans that are approved for a production licence also require minimum work commitments.

2.9 Requirements for Transfers of Interest in Upstream Licences
Provincial Crown Leases
In Alberta, British Columbia and Saskatchewan, there are generally no statutory or regulatory restrictions on transferring an interest in a Crown Lease from one party to another, provided that the transferee meets certain registration requirements. Most notably, if the transferee is a corporation, it must be registered to carry on business in the applicable province. Alberta will not recognise registered ownership of a Crown Lease by a partnership. Each of these provinces requires transfers to be registered with the Crown in a prescribed manner, which may include an electronic transfer.

Freehold Leases
Freehold Leases typically require notice of the transfer to be provided to the lessor. Some Freehold Leases also require the lessor to consent to the transfer.

Wells, Facilities
The transfer of licences to operate wells, facilities and pipelines requires that the relevant governing authority has confirmed that the transferee will be in compliance with the rules, including that the licensee meets all applicable financial and safety requirements.

Offshore
Under the legislation that governs mineral interests that are offshore Nova Scotia or Newfoundland and Labrador, notice of a proposed transfer must be made to the relevant joint administrative agency, and approval of the joint administrative agency must be granted before the transfer will be registered. The joint administrative agency may establish conditions for that transfer, including the posting of security.

Contractual Restrictions
Private investors holding upstream licences in Canada often enter into joint venture arrangements with other private investors to develop projects. The agreements in respect of these joint venture arrangements often place various restrictions on transfers by joint venture participants, including requirements to obtain approvals from the other participants or to comply with the rights of first refusal that may be held by them. The terms of these restrictions vary, depending on the particular agreement.

Tax Consequences
Under the Tax Act, an interest in an oil and gas licence is "Canadian Resource Property", which is differentiated from capital property. Any gain realised on the disposition of an upstream licence will result in an income inclusion, subject to any applicable deductions, at full rates (rather than a capital gain, which receives preferred tax treatment in Canada). Proceeds from the disposition received on the transfer of an upstream licence would first be applied against the COGPE pool and then the CDE pool of the party that transferred the upstream licence, thereby reducing the balance of those pools to that extent. Any remaining proceeds would be included in the income of the taxpayer in the year they were incurred. The party that receives the upstream licence would add the capital cost associated with the acquisition of the upstream licence to its COGPE pool.

Competition and Investment Canada Act Considerations
If certain thresholds are met, the transfer of interests in upstream licences will be subject to notification and review under either or both of the federal Competition Act and the Investment Canada Act. Generally speaking, asset acquisitions are notifiable under the Competition Act if the parties to the transaction, together with their affiliates, have in the aggregate either assets in Canada or gross revenues from sales in, from or into Canada in excess of CAD400 million, and if the book value of the assets in Canada subject to the transfer or the gross revenues from sales in or from Canada generated by those assets exceed CAD92 million (this is the threshold for 2018; the threshold for the "size of the target" is subject to potential indexing for inflation, and the new threshold is generally announced in early February of each year).

The Commissioner of Competition, who heads the Competition Bureau, may challenge any transaction before the Competition Tribunal or, where a remedy can be agreed, enter into a consent agreement with the parties in respect of any transaction where he or she is of the view that it is likely to substantially lessen or prevent competition in Canada. Competition law challenges of transactions involving the transfer of interests in upstream licences are very rare, but notifications are nonetheless required where the applicable thresholds are met. Similar thresholds apply to acquisitions of shares in corporations owning upstream licences, and to the acquisition of interests in unincorporated business combinations that own upstream licences.

All acquisitions of control of a Canadian business by a non-Canadian controlled investor, as well as the start-up of a new Canadian business by a non-Canadian investor, are subject to the Investment Canada Act and require either a relatively simple notification or, in the case of the acquisition of control of an existing Canadian business above a certain size, Ministerial review and approval (often required in advance of closing). See **4.1 Foreign Investment Rules Applicable to Investments in Petroleum** for further details.

3. Private Investment in Petroleum - Downstream

3.1 Forms of Allowed Private Investment
There are no prescribed forms for private investment in downstream operations. Downstream licences in respect of pipelines and plants are generally in the form of the required regulatory approvals for those facilities. The terms of those regulatory approvals are unique to each project, particularly for interprovincial undertakings.

Any proposed downstream operation involving the construction of new pipelines or plants would be subject to regulatory approval. Depending on the size and scope of the project (including whether it crosses provincial borders), the project will be reviewed by either provincial or federal regulators. In certain circumstances, regulators from both levels of government will be involved, and will form a joint review panel to assess the project.

Private investors may participate in downstream operations, including the development, ownership and operation of new or existing pipelines or plants (including refineries) or interests therein. Private investors may conduct those downstream operations alone or in conjunction with other private investors. Where there are multiple investors, they may choose to structure the ownership, development and/or operation of the applicable downstream operation through a joint venture, a partnership, a corporation or another type of entity created specifically for the investment.

However, foreign investment in existing downstream businesses or assets will be subject to any applicable restrictions under the *Investment Canada Act*. In addition, acquisitions of downstream businesses or assets and the conduct of downstream operations will be subject to Canadian competition laws and other applicable regulation. Those foreign investment and competition laws are described in **2.9 Requirements for Transfers of Interest in Upstream Licences** above and **4.1 Foreign Investment Rules Applicable to Investments in Petroleum** below.

3.2 Rights and Terms of Access to Any Downstream Operation Run by a National Monopoly

There is no state ownership of federal downstream facilities, including pipelines. In some provinces, Crown corporations own and operate gas distribution pipelines located wholly within the province.

The rights and terms of access to federally and provincially regulated monopoly pipelines are generally governed by tariff terms and conditions of service that are either accepted or approved by the applicable regulator that has jurisdiction, and that provide for open access to allow third party shippers to have their commodity transported on a non-discriminatory basis.

3.3 Issuing Downstream Licences

Licences for downstream facilities, including pipelines, are issued by the applicable federal or provincial regulators having jurisdiction. The construction and operation of pipelines that cross provincial borders or connect with other pipelines at the international boundary are regulated by the NEB. The construction and operation of downstream facilities that are wholly within provincial boundaries are regulated in accordance with the laws of the applicable province, which, in some cases, establish regulatory boards to consider and determine facility development approval applications. Environmental approvals required for the development of downstream facilities are issued by the applicable federal and provincial ministries having jurisdiction.

Larger scale projects may be subjected to comprehensive public hearings, conducted by the applicable federal or provincial regulatory boards, and to comprehensive environmental impact assessments by federal and provincial agencies or authorities. In some cases, regulators do not have authority to issue approvals but make recommendations to the government, which in turn decides whether or not to authorise the issuance of approvals.

Public hearings provide an opportunity for potentially affected stakeholders, including Aboriginal groups, to test a proponent's development application regarding matters such as direct impacts on particular stakeholders; potential impacts on environmental components, climate change, wildlife and aquatic resources, land use and public safety, among others; and socio-economic impacts. It also enables stakeholders to present evidence and make submissions regarding why or why not a project should be approved and, if applicable, what conditions of construction and operation should be imposed upon the proponent.

3.4 Typical Fiscal Terms Under Downstream Licences

Economic regulation of pipelines by the applicable federal or provincial regulatory authority is typically undertaken using one of the following three methods:

- **Cost of Service** – under this methodology, the regulator approves a revenue requirement for the pipeline for each year, which is comprised of approved forecast costs for depreciation; debt expense; return on equity; capital expenses; operation, maintenance and administration expenses; and taxes. Tolls are set at a level that is intended to provide the pipeline with a reasonable opportunity to recover its revenue requirement from its shippers.

- **Negotiated Toll Settlements** – as an alternative to contested rate hearings under the cost of service methodology, regulators encourage pipeline owners and shippers to seek multi-year negotiated settlements that, if achieved and approved by the regulator, establish the basis on which a pipeline's revenue requirement and resulting tolls are determined for each year of the settlement period.

- **Market Based Rates** ("**MBR**") – under this methodology, the proponent of a proposed pipeline or capacity expansion conducts an open season under which potential shippers are provided the opportunity to enter into firm service contracts under which prescribed toll levels are linked to a specified term of the contract offered by the pipeline and selected by the shipper. The toll for a 15-year term is less than that for a ten-year term, which is less than that for a five-year term. MBR permit shippers to choose an acceptable financial commitment and provide the pipeline with the necessary financial underpinning to proceed with the project, if minimum capacity subscription levels are met or exceeded.

In Canada, there are general principles of financial regulation that state that pipeline tolls must be just and reasonable and not unduly discriminatory. Shippers generally have the right to file complaints with the rate-making regulator on the basis of a pipeline's tolls being contrary to these principles, and, following the completion of the required process, the regulator may order that tolls be adjusted.

3.5 Income or Profits Tax Regime Applicable to Downstream Operations

The tax regime that applies to downstream operations is similar to the tax regime described in **2.4 Income or Profits Tax Regime Applicable to Upstream Operations** above, regarding the taxation of upstream operations. However, the use of COGPE, CDE and CEE will be limited, as the scope of what is covered by those specific resource pools is not generally available in respect of downstream operations.

Capital costs for downstream operations tend to be centred on tangible assets. The applicable CCA rates for downstream equipment vary from the typical Class 41 rates applied in the upstream operations. Manufacturing and processing equipment for a refining facility are typically Class 43 assets (CCA rate of 30%), while pipelines are generally Class 49 assets (CCA rate of 8%) or Class 8 assets (CCA rate of 20%), depending on the intended number of years of service of the applicable pipeline.

Specific legislation relating to Canada's emerging LNG market has led the provincial government in British Columbia to introduce a new tax regime for profits arising from LNG facilities. The tax regime has two fundamental components:

- a tier 1 tax of 1.5% of net operating income; and
- a tier 2 tax at an initial rate of 3.5% of net income.

The 3.5% tier 2 tax is effective for taxation years beginning on or after January 1, 2017. The 1.5% tier 1 tax applies during the period while net operating losses and capital investment are recovered, after which the 3.5% tier 2 tax applies, and is creditable against the 3.5% tier 2 tax.

In 2037, the tier 2 tax will increase to 5% of net income.

The application of GST/HST or PST discussed under the taxation of upstream operations would also apply to the sale of taxable supplies made in downstream operations.

Various jurisdictions within Canada also impose carbon tax regimes, as discussed in **5.5 Climate Change Laws** and **6.4 Material Changes in Oil and Gas Law or Regulation**, which can affect downstream operations.

3.6 Special Rights for National Oil or Gas Companies

As previously discussed, Canada does not have a national oil and gas company, and Newfoundland and Labrador's wholly owned oil and gas company does not have any special rights with respect to downstream licences.

3.7 Local Content Requirements Applicable to Downstream Operations

The Canadian federal government and provincial governments also seek to attract investment into downstream operations, so they do not typically require the use of local goods, services or employment.

As discussed in relation to upstream operations, downstream operators may also negotiate benefit agreements with local Aboriginal groups.A foreign-owned private investor acquiring a downstream Canadian business may also be subject to review under the ICA, which may result in the federal government requiring a foreign investor to make undertakings regarding the retention of Canadian employees and senior staff, as well as requiring the acquisition of Canadian goods and services (see **2.6 Local Content Requirements Applicable to Upstream operations** above).

3.8 Other Key Terms of Each Type of Downstream Licence

The statutory mandates of federal and provincial authorities that have responsibility to issue licences or approvals for downstream facilities generally include that the development of a project must be in the public interest. The public interest is determined by balancing the benefits and adverse affects of a project, having regard to matters such as:

- economic impacts;
- facility design and integrity;
- safety, emergency preparedness and response planning;
- environmental impacts and mitigation;
- potential effects on Aboriginal interests;
- impacts on other stakeholders; and
- reclamation.

The conditions that are normally included in facility licences and approvals are directed towards these matters in order to mitigate potentially adverse impacts and effects. These conditions cover three periods: pre-construction, construction, and post-construction and operation. They normally include a requirement for facilities to be built in accordance with industry specifications and standards and any commitments made in a project application, and a requirement that those facilities be constructed in accordance with all applicable safety and environmental laws and standards.

The conditions may also prescribe the filing of various plans, reports and confirmations. For example, conditions that have been imposed by the NEB include requirements that the following types of information be filed:

- a pipeline environmental protection plan;
- Aboriginal consultation reports;
- a commitments tracking table;
- construction activity, progress and mitigation reports;
- a pressure testing programme;
- welding procedures;
- operational consultation plans with Aboriginal groups and landowners;
- a condition compliance report;
- issues resolution tracking reports; and
- post-construction environmental tracking reports.

3.9 Condemnation/Eminent Domain Rights

Private investors must acquire the rights to access the surface of the lands required for the applicable downstream project after obtaining downstream licences. No private investor has a right-of-entry ("**ROE**") in respect of the surface of land until it has obtained the consent of the owner and occupier of that land. If that consent cannot be obtained through negotiations between the private investor and the applicable owner and occupier, an ROE order may be granted by a provincial surface rights tribunal with respect to both private and public land to allow the private investor the necessary access to conduct the applicable downstream operations, including constructing and operating the facilities that have been approved. A private investor that obtains an ROE order from a provincial surface rights board must pay an entry fee and additional compensation to the land owner or occupant.

3.10 Rules for Third Party Access to Infrastructure

All federally regulated oil pipelines (including pipelines that carry oil, natural gas liquids and petroleum products) operate as common carriers under the *National Energy Board Act,* which means that they must receive, transport and deliver all oil offered to them. Accordingly, the pipeline company prorates its available capacity to accommodate all shippers. If there is no remaining capacity on the pipeline, the National Energy Board can order a pipeline company to expand its pipeline to meet capacity requirements.

Unlike oil pipelines, natural gas pipelines are operated as contract carriers, which means they are not required by the *National Energy Board Act* to accept all natural gas offered to them by a shipper. However, the NEB is authorised to direct a pipeline company to offer natural gas pipeline capacity to a shipper.

Provincial legislation governs interprovincial pipelines – ie, pipelines that do not cross provincial borders. In Alberta, the *Oil and Gas Conservation Act* effects the conservation – and prevents the waste – of oil and natural gas resources in Alberta, and provides for the economic, orderly and efficient development of oil and natural gas resources in the public interest. Under section 48 of the *Oil and Gas Conservation Act*, the Alberta Energy Regulator may declare each pipeline company to be a common carrier of oil, natural gas or synthetic crude. An order under this section obliges each common carrier, among other things, to provide equal opportunity to each owner of oil, natural gas or synthetic crude, as applicable, to have its production transported. As such, a common carrier order allows an owner to share in the existing capacity of the pipeline. In exercising its powers, the AER considers whether the applicant has been reasonable in trying to negotiate the terms of transportation with the pipeline owner, and whether the proposed common carrier pipeline is the only economically feasible way to transport the production in question, in the most practical way, or clearly the environmentally superior way. The *Oil and Gas Conservation Act* gives the AER similar powers in relation to natural gas processing plant capacity.

Similar legislation is in place in Saskatchewan (excluding pipelines for the transportation of natural gas) under the *Pipeline Act* (Saskatchewan) and in British Columbia under the *Pipeline Act* (B.C.), again only in relation to the transportation of oil.

3.11 Restrictions on Product Sales into the Local Market

There are no restrictions on product sales into the local market, except for the following:

- an order or licence from the NEB is required to import natural gas into Canada; and
- consumer protection legislation and other laws and regulations of general application, including Canadian competition laws and administrative requirements such as reporting and licensing obligations.

3.12 Requirements for Transfers of Interest in Downstream Licences

The transfer of downstream licences requires regulatory approval from the applicable regulator.

As noted in **2.9 Requirements for Transfers of Interest in Upstream Licences** above, transactions meeting certain thresholds may require advance notification and review under the federal *Competition Act* and/or, as discussed below, the *Investment Canada Act*. Given fewer participants in the midstream and downstream sectors, careful consideration of the likely impact of the transfer of midstream and downstream interests is advisable when planning a transaction. The transfer of interests in pipelines may also require notification to the federal Minister of Transportation.

Provincially Regulated Facilities

For provincially regulated facilities, the transferee must submit a transfer application to the applicable provincial regulator for approval. Provincial regulators such as the AER typically require the transferee to satisfy the same requirements imposed on the initial applicant in order to qualify for a transfer. The regulator will review the compliance record of both the transferee and the transferor for any issues that may affect future liabilities. Furthermore, the regulator may require a security deposit if it determines that the applicant may be unable to address potential liabilities, particularly costs associated with reclamation, accidents or malfunctions. Transferees who will become first-time licensees as a result of a transfer will also be required to pay the applicable registration and transfer fees in most jurisdictions.

Federally Regulated Facilities

For federally regulated facilities, the transferring parties must apply to the National Energy Board for leave to affect a transfer. The NEB will assess whether the proposed transfer is in the public interest, considering how the transfer will affect applicable economic, environmental and social interests along with the adequacy of the transferee's proposed strategies and mitigation measures.

Contractual Restrictions
In addition to obtaining the required regulatory approvals, transferring parties must address any contractual restrictions affecting the transfer of a downstream licence. It is common for downstream operators in Canada to enter into joint venture arrangements with other private investors to develop projects. These agreements often place various restrictions on transfers by joint venture participants, including requirements to obtain approvals from the other participants or to comply with the rights of first refusal that may be held by them.

Tax Consequences
The Tax Act treats a transfer of a downstream licence as a disposition, which generally gives rise to recapture/capital gain (or loss), depending on the tax attributes of the downstream licence to the taxpayer.

One-half of capital gains in excess of one-half of capital losses realised by a taxpayer in a particular year is included in income and is subject to income tax at regular rates under the Tax Act, and any applicable provincial/territorial legislation.

4. Foreign Investment

4.1 Foreign Investment Rules Applicable to Investments in Petroleum

The *Investment Canada Act* (ICA) applies when a non-Canadian (ie, an individual that is neither a Canadian citizen nor a permanent resident, or an "entity" or government or agency thereof that is not Canadian-controlled) establishes a new business in Canada, proposes to acquire control of a Canadian business directly or indirectly, or acquires an interest in a Canadian business which acquisition could be injurious to national security.

Note that the term "Canadian business" is defined in the ICA and refers to a business located in Canada, regardless of who controls it. Under ICA guidelines, a property on which only exploration for oil or gas has been conducted may not be considered to be a business, depending on the circumstances. If a property has reserves and production has occurred, it is considered to be a business. The Canadian business being acquired does not need to be Canadian-controlled in order for the *ICA* to apply to an acquisition of control of that business (ie, a transfer from one non-Canadian to another non-Canadian is also covered).

Certain investments where the enterprise value or asset value of the Canadian business exceeds prescribed monetary thresholds are subject to approval by the federal government. If the investment is reviewable because it exceeds the monetary thresholds, the investor must demonstrate that the investment is likely to be of net benefit to Canada according to certain prescribed (largely economic) criteria. Where subject to "net benefit" review, the investor will generally be required to enter into binding undertakings with the federal government in respect of the future governance and conduct of the Canadian business. All other acquisitions of control and establishments of new Canadian businesses are subject to a notification process only, but may be subject to a national security review (see below).

A *direct* acquisition of control of a Canadian business (ie, one located in Canada) by a non-Canadian investor controlled by nationals of a World Trade Organization ("**WTO**") member, or a sale of that kind of a business when it is controlled by a WTO investor, is only reviewable on a pre-closing basis by the Minister of Innovation, Science and Economic Development (formerly called the Minister of Industry) if the enterprise value of the Canadian business exceeds CAD1 billion. Investors from certain jurisdictions with trade agreements with Canada, including the European Union, Mexico and the United States, enjoy a higher threshold of CAD1.5 billion. Indirect acquisitions of control by WTO investors of non-cultural businesses are not subject to net benefit review, and require notification only.

Investments by state-owned enterprises ("**SOEs**"), including sovereign wealth funds (and any person or entity that is "controlled or influenced" by a foreign government), are subject to a different threshold for review, based on the book value of assets of the Canadian business. The threshold is indexed annually for inflation and, for 2018, has been set at CAD398 million. Investments by SOEs are analysed under the usual "net benefit" factors in the ICA, as well as special guidelines that refer to the nature and extent of control by the foreign government, the SOE's corporate governance, operating and reporting practices, the SOE's adherence to free market principles, the effect of the investment on the level and nature of economic activity in Canada, and whether the acquired Canadian business will retain the ability to operate on a commercial basis.

The Canadian government has a lower tolerance for SOEs acquiring control of, or material influence over, leading firms in many sectors of Canada's economy. For example, investments in the Canadian oil sands by SOEs are only permitted in "exceptional" circumstances, although this policy appears to have been relaxed with the warming of Canada-China relations since the election in Canada of a new federal government in 2015.

The *ICA* also permits the federal government to review any investments in Canada (even if only a minority investment and regardless of whether the target is a "Canadian business") for national security purposes. Otherwise, "Canadian" investors can be deemed to be non-Canadian for purposes of national security reviews. Under guidelines for national security reviews released in December, 2016, the factors that could lead to a national security review include the transfer of "critical infrastructure", including networks, assets and services essential to the economic well-being of Canadians, as well as the impact of the investment on the supply of critical goods and services to Canadians. Certain petroleum infrastructure could potentially be considered to fall into these categories. National security reviews are relatively rare, and are only conducted if the Minister of ISED, after consulting with the Minister of Public Safety and Emergency Preparedness, determines that there is or could be a risk to Canada's national security.

5. Environmental, Health and Safety (EHS)

5.1 Principal Environmental Laws and Environmental Regulator(s)

The federal and provincial governments have shared jurisdiction over the environment, and there are a variety of environmental protection and environmental assessment statutes in the various jurisdictions.

The principal federal environmental regulators for oil and gas operations are the Canadian Environmental Assessment Agency and the National Energy Board ("**NEB**"). The chief federal environmental legislation relating to the regulation of hazardous or toxic substances is the *Canadian Environmental Protection Act*. Additionally, the *Canadian Environmental Assessment Act, 2012* ("**CEAA**") outlines the responsibilities and procedures for carrying out environmental assessments of projects falling under federal jurisdiction. Impacts from upstream and downstream operations on fish, migratory birds, endangered species and waterways are also regulated under the *Fisheries Act*, the *Migratory Bird Convention Act*, the *Species at Risk Act* and the *Navigation Protection Act*, respectively.

On February 8, 2018, the federal government introduced *An Act to enact the Impact Assessment Act and the Canadian Energy Regulatory Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts* (" **Bill C-69** "). Bill C-69 introduces revised environmental and regulatory processes, with a focus on rebuilding trust in the environmental assessment process, replacing the NEB with the Canadian Energy Regulator ("**CER**") and the Canadian Environmental Assessment Agency with the Impact Assessment Agency of Canada ("**IAAC**"), and introducing expanded safeguards under both the *Fisheries Act* and the *Navigation Protection Act*. The proposed expanded environmental protections in Bill C-69 include requirements for decisions of the proposed CER and IAAC to assess the indirect or cumulative impacts associated with a proposed project, the impacts to Indigenous peoples of Canada, including with respect to their current use of lands and resources for traditional purposes, the impacts to sustainability and Canada's ability to meet its climate change obligations, and an expansion of waterways that are considered "navigable waters" under the *Navigation Protection Act*. Bill C-69 also introduces standardised time limits for federal reviews of new projects. Bill C-69 passed in the House of Commons on June 20, 2018, with the first reading of the bill in the Senate taking place on the same day. Bill C-69 is anticipated to be enacted in the spring of 2019.

At the provincial level, there are differing approaches to the regulation of the environment. Some provinces have a single oil and gas regulator that also has jurisdiction over environmental matters related to those kinds of projects, while in other provinces there are multiple regulators or shared jurisdiction between an oil and gas regulator and the Ministry of Environment.

In Alberta, the AER is the single regulator responsible for conducting environmental assessments and issuing environmental permits associated with oil and gas activities, including upstream oil, oil sands, natural gas, and coal development and downstream facilities in the province. In British Columbia, the British Columbia Oil and Gas Commission regulates activities related to exploration, development, pipeline transportation and reclamation, while the British Columbia Environmental Assessment Office manages the review of proposed major projects under BC's environmental assessment legislation. In Saskatchewan and Ontario, however, it is the Ministry of Environment and the Ministry of Environment and Climate Change, respectively, that have jurisdiction over environmental matters as they pertain to oil and gas activities.

5.2 Environmental Obligations for a Major Petroleum Project

As noted above, jurisdiction over the environment is shared between Canada and its provinces. Accordingly, there are a range of environmental obligations that may need to be met, depending on the scope of the petroleum project and its associated environmental impacts. It may be necessary to obtain environmental or water permits associated with the petroleum project, and it may be necessary to undertake a comprehensive provincial or federal environmental assessment. Major upstream and downstream petroleum projects are generally required to complete a rigorous environmental assessment process to evaluate the associated environmental impacts of the project and whether such impacts may cause significant adverse effects on the environment.

Under the *Canadian Environmental Assessment Act, 2012* ("**CEAA**"), the activities listed in the *Regulations Designating Physical Activities* require a federal environmental assessment by the Canadian Environmental Assessment Agency or the NEB. It remains to be seen whether similar activities will be listed in any regulations under Bill C-69 when it is enacted into law. Similar lists are found in regulations under the various provincial environmental assessment statutes. Other projects may be subject to a provincial environmental assessment under the respective provincial environmental assessment legislation. Furthermore, even where a petroleum project is not listed, the Minister of the Environment in the particular jurisdiction generally has the discretion to require an environmental assessment for that project. While it may be the case that either a federal or provincial environmental assessment can be substituted for the other in order to harmonise the process and avoid duplication, a recent case from British Columbia suggests that certain statutory requirements cannot be delegated or substituted, with the result that it may be necessary to undertake separate federal and provincial environmental assessments in some instances.

Regulatory permitting generally occurs after the environmental assessment has been completed, in circumstances where one is required. The project proponent submits applications and supporting documentation to the provincial regulator for specific land use, construction, operating, emissions and environmental approvals. Typically, these relate to air, water, safety, noise, heritage resources, aesthetics, traffic, and wildlife habitat.

Before commencing a major petroleum project, it may also be necessary under federal or provincial legislation to provide security for abandonment, reclamation and remediation obligations associated with the project. Some jurisdictions also require the payment of certain levies into an orphan well fund designed to provide provincial regulators with the required resources to fund abandonment and reclamation work associated with any wells and facilities of insolvent companies that fail to meet these requirements.

5.3 EHS Requirements Applicable to Offshore Development

The *Offshore Health and Safety Act* was enacted by the federal government in 2014 with the objective of ensuring the safety of offshore workers and workers in transit to offshore platforms. In addition, it was specifically set up to:

- require that any occupational health and safety regulations that apply to the transportation of persons to, from or between workplaces in the offshore areas be made on the recommendation of the federal Minister of Transport; and
- authorise the Canada-Newfoundland and Labrador Offshore Petroleum Board and the Canada-Nova Scotia Offshore Petroleum Board to publicly disclose information related to occupational health and safety if it considers it to be in the public interest.

The legislation was as a result of extensive collaboration between the provincial governments of Newfoundland and Labrador and the federal government, amending a number of other pieces of federal legislation to improve the enforcement powers under those Acts (for example, the *Hazardous Materials Information Review Act*, the *Access to Information Act* and the *Canada Labour Code*, among others). For certain offences under the *Offshore Health and Safety Act*, fines of up to CAD100,000 and imprisonment for up to a maximum of one year (or both) on summary conviction may be imposed, and fines of up to CAD1 million or imprisonment for a maximum of five years (or both) on indictment may be imposed.

Provincial legislation (for example, in relation to labour standards, worker compensation and health) also applies to offshore workplaces to the extent it is not inconsistent with the federal regime. The *Energy Safety and Security Act* (Canada) came into force in February of 2016 and introduced new measures to strengthen environmental protection and safety in Canada's offshore oil and gas industry by enshrining "polluter-pays" principles, consistent with the notion that the liability of an "at-fault" operator is unlimited, increasing the limit of liability to CAD1 billion without proof of fault or negligence under certain circumstances, requiring an operator to demonstrate it has the financial resources to pay the full extent of the liability that might apply to it, dealing with document disclosure and creating a framework to allow for the safe use of spill treating agents in prescribed circumstances. The legislation requires emergency planning, environmental plans and other documents to be made available to the public, with a view to ensuring that the public can review and understand the steps operators will take to prevent and respond to incidents.

5.4 Requirements for Decommissioning

The decommissioning of oil and gas assets and projects is required by law when the oil and gas activities on the lands end.

A decommissioning (or reclamation) plan is typically created prior to the commencement of a project and is generally continually updated over a project's life to include changes in field development, new decommissioning techniques developed by industry and changes to regulatory requirements. These plans usually address all aspects of the project from beginning to end, and include an analysis of how contaminants are going to be cleaned and how revegetation of the land will be addressed, among other remediation and reclamation activities. After completion of a project, the operator will then submit this plan to the relevant regulator, seeking approval to decommission the project by way of a reclamation certificate, which ensures that the project will not pose a future risk to the public and that the sites are restored to a safe condition, minimising residual environmental impacts while permitting the reinstatement of activities.

In most jurisdictions in Canada, project sites must be returned to a state of equivalent land capacity in order to receive a reclamation certificate. This will involve removing equipment or buildings and other structures; decontaminating buildings or other structures, land or water; and stabilising, contouring, maintaining or reconstructing the land to restore it to a similar condition, among other things depending on the nature of the relevant asset. Generally, the reclaimed land must be able to support specific prescribed uses, and the regulator must be satisfied of such before granting a reclamation certificate. Regulators in some jurisdictions expect that companies will continue to monitor decommissioned projects and consult with affected parties both during and after the decommissioning period. In some jurisdictions, the operator remains liable for surface issues after a reclamation certificate has been issued, ensuring the sites are continually found to be compliant with the reclamation criteria.

Typically, the operator is responsible for the cost of decommissioning, and the regulator ensures that the operator posts security in an amount that is sufficient to carry out the suspension, decommissioning, remediation and surface reclamation work to the standards mandated by the relevant legislation. In relation to upstream oil and gas assets, the provincial governments in Alberta, Saskatchewan and British Columbia have legislated licensee liability rating programmes, which are designed to minimise the risk of unfunded abandonment and reclamation liabilities. The regulator uses the ratio of an operator's deemed assets to deemed liabilities to determine whether the operator is sufficiently financially solvent to fund the required reclamation activities. Depending on the result of the calculation, an operator may be required to post a security deposit with the regulator. In relation to oil sands mining projects in Alberta, a different programme is used (the Mine Financial Security Programme), pursuant to which the operator is subject to different types of financial security deposits, each focusing on the separate risks that relate to the lifecycle of a mine.

These financial security programmes are intended to ensure that a balance is struck between protecting the public from the costs associated with an oil and gas development and reclamation and remediation, while maximising an operator's opportunity for responsible and sustainable resource development.

5.5 Climate Change Laws

Canada is a signatory to the United Nations Framework Convention on Climate Change ("**UNFCCC**") and the 2015 Paris Agreement. Canada filed its Intended Nationally Determined Contribution ("**INDC"**) with the UNFCCC, reflecting its intention to reduce its greenhouse gas emissions by 30% below 2005 levels by 2030. INDCs constitute the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit global temperatures from rising more than 1.5° Celsius. The UNFCCC adopted the Paris Agreement on December 12, 2015.

Federal

On December 9, 2016, the government of Canada formally announced the *Pan-Canadian Framework on Clean Growth and Climate Change*. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning January 1, 2019. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of CAD10 per tonne on any province or territory that fails to implement its own system by 2019. This amount will increase by CAD10 annually until it reaches CAD50 per tonne in 2022, at which time the programme will be reviewed.

British Columbia

In British Columbia, the *Greenhouse Gas Reduction Targets Act* sets aggressive legislated targets for reducing greenhouse gases. Under that act, GHG emissions are to be reduced by at least 33% below 2007 levels by 2020 and 80% below 2007 by 2050. The *Carbon Tax Act* establishes a broad tax based on the estimated emissions from the purchase or use of fuels and the use of combustibles when used to produce heat or energy. In 2018, the tax is set at CAD35 per tonne of CO2e and will increase each year by CAD5 until it reaches CAD50 per tonne of CO2e in 2021. In addition to the economy-wide carbon tax, BC has passed legislation that imposes GHG emissions limits and permits emissions offset projects under the *Greenhouse Gas Industrial Reporting and Control Act*. That act currently only applies limits to LNG operations and power generation.

Alberta

In anticipation of the foregoing announcement, many Canadian provinces have already enacted legislation to place limits and a price on carbon emissions. Alberta introduced the *Climate Leadership Act*, which implemented an economy-wide levy of CAD20 per tonne of CO2e effective January 1, 2017, increasing to CAD30 per tonne effective January 1, 2018. All fuel consumption – including gasoline and natural gas – is subject to the levy, with certain exemptions.

Specific to oil sands development, in December of 2016 the province of Alberta enacted the *Oil Sands Emissions Limit Act*, which places a limit of 100 megatonnes per year of CO2e emissions from oil and sands operations (with specific exceptions for cogeneration and upgrading). The *Specified Gas Emitters Regulation* was replaced at the end of 2017 with the enactment of the *Carbon Competitiveness Incentive Regulation* ("**CCIR**"), which sets sector-specific output-based carbon allocations for facilities that emit 100,000 tonnes or more of CO2e per year, and allows certain competitively impacted facilities not otherwise subject to the CCIR to opt-in to the emissions regime in lieu of paying the emissions levy. The CCIR requires operations to reduce their emissions intensity (ie, the quantity of GHG emissions per unit of production) from baselines established in accordance with the CCIR. Regulated emitters are required to reduce their emissions intensity by 3% from their baseline in the fourth year of commercial operation, to a total of 20% of their baseline in the ninth and subsequent years. Compliance can be achieved through a combination of the following:

- reducing emissions;
- purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols);
- purchasing emissions performance credits from other regulated emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold; or
- contributing to the Climate Change and Emissions Management Fund at a rate of CAD30 per tonne of GHG emissions.

Additionally, the province of Alberta has set a target of reducing methane emissions from oil and gas operations by 45% by 2025, which will be achieved through new emission design standards for new facilities, a five-year voluntary methane reduction initiative and regulated mandatory standards starting in 2020.

Saskatchewan

Saskatchewan does not currently have any carbon pricing legislation in place. It released its Prairie Resilience climate framework in December 2017, which proposes to subject emitters of more than 25,000 tonnes CO2e annually to certain standards. The federal government has indicated that the framework does not satisfy the federal carbon pricing requirements, and that Saskatchewan will be subject to the federal backstop carbon price.

Saskatchewan has publicly opposed federal carbon pricing and intends to challenge the federal legislation in court.

Manitoba

The *Fuel and Carbon Tax Act* will establish a tax, initially set at CAD25 per tonne of CO2e, on the purchase or use of fuels in Manitoba, subject to certain exemptions. The *Industrial Greenhouse Gas Emissions Control and Reporting Act* will require industrial emitters who emit more than 50,000 tonnes of CO2e annually to report their emissions and comply with emission limits. The legislation provides that participants will receive credits if they emit less than the emissions limit set by regulation. Participants who emit more than the limit are required to pay CAD25 per tonne of CO2e or to remit credits equal to their excess emissions.

Ontario

Ontario's cap-and-trade programme is governed by the *Climate Change Mitigation and Low Carbon Economy Act* and related regulation. On July 4, 2018, the Ontario government announced its intention to terminate the cap-and-trade programme, and has indicated that it will join Saskatchewan's court challenge of federal carbon legislation.

Quebec

Quebec's cap-and-trade programme is governed by the *Environmental Quality Act* and related regulation, and requires that industrial facilities and natural gas distributors with emissions of 25,000 tonnes or more of greenhouse gas emissions per year participate in the programme. Fuel suppliers that sell more than 200 litres of fuel per year and electricity importers are also required to participate. Quebec is part of the Western Climate Initiative (the "**WCI**"), which hosts joint emission credit auctions with California.

Under the cap-and-trade programme, emitters are required to obtain a number of allowances equal to their total emissions within a given compliance period. Allowances are typically obtained through a government-managed auction process. Certain emitters, including refineries and other large emitters, may be eligible to receive a number of free allowances from the government to offset the costs associated with the cap-and-trade programme. Emitters are usually eligible to receive free allowances when they operate in a competitively sensitive industry. The number of free allowances granted by the province is anticipated to decline over time.

New Brunswick

Under the *Climate Change Act*, New Brunswick is intending to redirect a portion of existing tax revenues on motor fuels to programmes that combat climate change. The federal government has indicated that the New Brunswick plan does not satisfy the federal carbon pricing requirements, and that the province may be subject to the federal backstop carbon price.

Nova Scotia

Under the *Environmental Act* and related regulation, Nova Scotia intends to implement a cap-and-trade programme similar to Quebec. Facilities with annual emissions of 50,000 tonnes of CO2e or more, natural gas distributers with annual emissions of 10,000 tonnes of CO2e or more, and fuel suppliers that import or produce 200 litres of fuel or more annually will be required to participate in the cap-and-trade programme. At this time, Nova Scotia does not intend to link to the WCI.

Newfoundland and Labrador

Under the *Management of Greenhouse Gas Act* and related regulation, Newfoundland and Labrador intends to implement a carbon tax covering industrial facilities that emit 15,000 tonnes or more of CO2e annually.

Prince Edward Island

Prince Edward Island does not currently have carbon pricing legislation in place. The Climate Action Plan released by the province indicates that it will rely on the federal backstop carbon price for industrial emitters.

6. Miscellaneous

6.1 Unconventional Upstream Interests

Unconventional upstream interests, including tight oil, tight gas, shale gas and coal bed methane, are subject to the same tenure and other regulations respecting upstream operations as apply to conventional upstream interests. Oil sands are not considered to be an unconventional resource.

Hydraulic fracturing is more prevalent in the development of unconventional resources. Due to concerns raised regarding hydraulic fracturing, various regulatory agencies have instituted additional safeguards and reporting requirements for hydraulic fracturing operations. There is a full temporary moratorium on the utilisation of hydraulic fracturing for the St. Lawrence area in Quebec and all of New Brunswick while further studies are undertaken. Alberta and British Columbia have instituted a reporting requirement for the amounts and sources of water and chemicals used, while the National Energy Board has requested that similar reporting be done on operations where it has jurisdiction. The reports are made to a public registry at www.fracfocus.ca and, as a result, are available for the public to review.

Additional monitoring and reporting requirements have been instituted in areas where concerns have arisen that prior hydraulic fracturing has created seismic events.

Also, due to the advantages of drilling multiple horizontal wells for unconventional production from a single surface location, special rules have been developed regarding the spacing of wells and the sharing of royalty revenue.

Alberta is reviewing whether coal bed methane should be subject to a separate set of regulations. In some jurisdictions, including Alberta, operators are required to obtain a licence or approval before the removal of non-saline water from a coal seam, and the disposal of water used in the process is subject to strict regulations.

6.2 Liquefied Natural Gas (LNG) Projects

LNG export projects in Canada fall under many of the same environmental and regulatory regimes as other downstream operations, as described above.

Since 2008, there have been almost 20 proposals to build LNG export terminals in Canada, mostly on the West Coast of British Columbia, with a few proposed for the Atlantic provinces and Quebec. The leading proposals in British Columbia are the Shell-led LNG Canada syndicate (24 million tonnes per annum ("MTPA") in capacity), the Petronas-led Pacific NorthWest LNG syndicate (18 MTPA), the Kitimat LNG joint venture between Chevron and Woodside (10 MTPA) and the relatively smaller Woodfibre LNG project (2.1 MTPA). Outside British Columbia, Goldboro LNG in Nova Scotia (10 MTPA) appears to be the most advanced. Canada has no operational LNG export facilities and, to date, only Woodfibre LNG has taken a Final Investment Decision to proceed to construction.

Most of these proposed LNG export terminals require both federal and provincial environmental assessments and approvals before commencing construction or operation.

In addition, most of these proposed projects require new pipelines or the expansion of existing pipelines to ship the natural gas to those terminals for liquefaction. Intra-provincial pipelines, like the ones principally involved in moving natural gas from fields in north eastern British Columbia to proposed export facilities on the coast, are provincially regulated. Pipelines that cross a provincial or international boundary are federally regulated by the NEB.

In order to export LNG from Canada, a permit must be obtained from the NEB, which reviews export licence applications to ensure that the proposed volume of natural gas to be exported from Canada is surplus to Canadian requirements. The NEB has issued numerous export licences for periods of up to 40 years. In particular, LNG Canada, Pacific NorthWest LNG, Kitimat LNG, Woodfibre LNG and Goldboro LNG all hold the necessary and required NEB export licences.

In July 2015, British Columbia passed the *Liquefied Natural Gas Project Agreements Act,* which provides the provincial government in British Columbia with authority to enter into LNG project agreements with project proponents. As far as is known, there are no specific additional tax or legal regimes governing proposed LNG projects in Eastern Canada outside of the *NEB Act* and the *CEAA*.

The regulation of the ongoing operation of LNG export terminals generally falls to the provinces where the terminals are located. Once in operation, LNG projects in British Columbia will be subject to certain LNG-specific provincial regulations, including the *BC Liquefied Natural Gas Income Tax Act* ("LNG Tax Act"), which imposes a two-tier tax on income derived from liquefaction activities in British Columbia. Initially imposed at a rate of 1.5%, the rate increases to 3.5% once eligible capital expenditures and certain other early-stage costs have been recovered. In 2037, that 3.5% rate increases to 5%.

British Columbia has also enacted the *Greenhouse Gas Industrial Reporting and Control Act* ("GHG Control Act"), to which any BC-based LNG plants will be subject. The *GHG Control Act* establishes a carbon emissions intensity threshold of 0.16 tonnes of CO2e per tonne of LNG. Emissions above that threshold attract the requirement to purchase carbon offsets or to contribute CAD25/tonne of CO2e to a BC clean technology fund.

6.3 Unique or Interesting Aspects of the Petroleum Industry

Oil Sands

Canada's oil sands are one of the largest reserves of petroleum in the world, and 97% of all of Canada's oil reserves are in Alberta's oil sands. Several recent studies predict significant growth in Canadian oil production over the next 25 years, with the majority of the Canadian oil production that will be required to offset declines from existing sources and to supply increased demand expected to come from the oil sands.

Private investors may participate in upstream operations in the oil sands, but foreign investment in existing oil sands businesses or assets, particularly by state-owned enterprises, will be subject to applicable restrictions under the *Investment Canada Act.* In addition, Canadian competition laws will apply to investments in the oil sands. See **2.9 Requirements for Transfers of Interest in Upstream Licences**.

Aboriginal Issues

Canada has a significant Aboriginal population. The Crown has a duty to consult with and, where appropriate, accommodate Aboriginal groups when it contemplates conduct that might adversely affect potential or established Aboriginal or treaty rights. For example, the Crown's duty to consult would be triggered by an oil and gas project that would be constructed and operated within the traditional territory of an Aboriginal group, near an Indian reserve, or in an area that could affect wildlife hunted by an Aboriginal group. The contemplated Crown conduct that typically triggers the duty in these cases is the issuance of environmental approvals and permits to construct and operate the project. The Crown may delegate aspects of Aboriginal consultation to a project proponent and then rely on the consultation by that proponent to satisfy its duty to consult.

The scope of consultation depends on the Aboriginal right claimed and the degree of impact the activity has on the right. The required level of consultation to satisfy the duty to consult can range from mere notification to significant participatory rights in the decision-making process. For large energy projects, the Crown will generally delegate the duty to consult to the project proponent; however, it remains the Crown's responsibility at law to ensure there has been adequate consultation before granting approvals, as project approvals are at risk of being revoked by the courts where governments fail to consult adequately. This is currently a major theme in Canadian energy litigation. A record of meaningful Aboriginal consultation prepared by a project proponent can be key to obtaining regulatory approvals and avoiding costly court challenges.

6.4 Material Changes in Oil and Gas Law or Regulation

Material changes in oil and gas law and regulation in Canada over the past year include the following:

Bill C-48: The Oil Tanker Moratorium Act

May 8, 2018 saw the introduction of Bill C-48, *An Act Respecting the Regulation of Vessels that Transport Crude Oil or Persistent Oil to or from Ports or Marine Installations Located Along British Columbia's North Coast* ("Bill C-48"). If enacted, it will enact the *Oil Tanker Moratorium Act* ("OTMA"), which, in turn, will prohibit tankers from loading or unloading at marine installations and ports in northern BC. Ministerial exemption is possible under certain limited circumstances.

Implementation of British Columbia's New Spill Response Regime

On October 30, 2017, the first phase of British Columbia's new spill response regime came into force and, with it, three regulations concerning spill preparedness, response and recovery. The new programme requires regulated liquid petroleum product transporters to implement a provincial spill response plan based on a worst-case scenario, to test plan and to report on and clean up spills. There is also a duty to maintain records in relation to the plans and training. The regulations apply to all rail and highway transporters in possession, charge or control of 10,000 litres or more of liquid petroleum products, and to pipelines regardless of the quantity of such product in their pipeline. All transporters are required to have spill plans ready by October 30, 2018.

Alberta Carbon Competitiveness Regulation

In January 2018, the *Carbon Competitiveness Incentive Regulation* ("CCIR") came into force in Alberta. The CCIR is an intensity-based emissions programme by which the Government of Alberta expects to cut emissions by 20 million tonnes by 2020 and 50 million tonnes by 2030.

Canada's Climate Change Plan

In March 2018, the Office of the Auditor General of Canada (the "Auditor General") released a report summarising provincial audit findings respecting climate policy between November 2016 and March 2018. The report found that only two of the five provinces with greenhouse gas ("GHG") reduction goals were on track to meet those goals, and that the provincial governments were generally behind in their risk assessment and adaptation plans. The 2016 Climate Change Plan provided the provinces with an opportunity to opt into it by March 30, 2018, which no provinces did. The province of Saskatchewan has filed a reference that is yet to be heard to determine the constitutionality of the *Greenhouse Gas Pollution Pricing Act*, which was introduced to Parliament on March 28, 2018 and outlines the federal carbon pricing plan.

Amendments to Ontario's Cap and Trade Programmes

On January 1, 2018, the province of Ontario introduced amendments to its cap and trade programmes, with the effect of harmonising the programme with those in California and Quebec and increasing fairness and equitable treatment for programme participants. The changes allow for the recognition of compliance instruments from California or Quebec in Ontario, and introduced a common price for the compliance instruments between these jurisdictions. Participants with facilities in multiple jurisdictions are no longer confined to one jurisdiction but can instead register in and meet their compliance obligations in each jurisdiction.

Bill C-68: An Act to Amend the Fisheries Act and Other Acts in Consequences, 2018

Proposed amendments to the federal *Fisheries Act* have recently expanded the scope of its application. The proposed changes will capture and prohibit carrying on "any work, undertaking or activity, other than fishing that results in the death of fish." The amendments give the Minister broader discretion when making decisions, and impose on the Minister an obligation to take into account the impact of a Ministerial decision on the rights of Indigenous peoples. As well, the amendments have introduced "habitat credits" that can be used to offset the adverse effects a project may have on the habitat with which it interferes. These credits will be awarded to those who conduct or participate in a conservation project within a fish habitat.

Bill C-69: Canadian Energy Regulator Act

In 2018, the federal government introduced sweeping new legislation aimed at significantly reworking the federal environmental assessment regime, being Bill C-69, *An Act to enact the Impact Assessment Act* ("IAA") and the *Canadian Energy Regulator Act* ("CERA"). If enacted, it will be brought into force in early 2019 and will establish a Canadian Energy Regulator to replace the National Energy Board. The new regulator will exercise similar jurisdiction to that of the NEB, but "designated" projects under the IAA will have to be referred to a review panel if they include activities that are regulated under CERA. In addition, the legislation specifically directs the regulator to increase the involvement of Indigenous people in respect of energy project development, enhances transparency and expands the considerations to be made when determining if a pipeline is in the public interest.

Extractive Sector Transparency Measures Act in Effect for Payments to Indigenous Governments ("ESTMA")

As of June 1, 2017, the *ESTMA* creates an obligation to report payments made to Indigenous governments by entities that are listed on a Canadian stock exchange or meet a certain size, and that are engaged in the commercial development of oil, gas and minerals. While this does not create an obligation to disclose Impact and Benefit Agreements, certain payments made pursuant to these agreements may be required to be disclosed.

Alberta Energy Regulator Directive 67

In December of 2017, the Alberta Energy Regulator ("**AER**") issued Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licenses and Approvals*, which gives the AER expanded powers to place conditions on licensees and to collect information to aid in assessing whether a licensee poses an unreasonable risk to fund "end of life" activities for wells, pipelines and other facilities. When issuing Directive 067, the AER stated: "Acquiring and holding a licence or approval in Alberta is a privilege, not a right. This new edition of the Directive increases the scrutiny the AER applies to ensure that this privilege is only granted to, and retained by, responsible parties." The Directive requires existing licensees to submit updated information to the AER respecting the licensee, its directors and officers, and to provide a further update any time a material change, as defined in the Directive, takes place.

Bill 13: An Act to Secure Alberta's Electricity Future

Bill 13 outlines a framework to establish a capacity electricity market in Alberta. The first capacity auction is expected in 2019, and the capacity market is expected to commence

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operation in 2021. Bill 13 proposed several amendments to the *Alberta Utilities Act* to necessitate the capacity market; however, further developments are still required, including the creation of supporting regulations.

British Columbia Legislative Updates

In an overhaul of British Columbia's *Contaminated Site Regulation*, amendments were made that updated more than 8,500 environmental quality standards. Most notably, the standards relating to groundwater, soil and vapour were updated, based on new information available since the regulation's last update in 1997.

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