Annual Information Form

Capital Power Corporation

For the year ended December 31, 2018

19 February 2019

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form (AIF) is given at or for the period ended December 31, 2018. Amounts are expressed in Canadian dollars unless otherwise indicated. All financial information presented in millions of Canadian dollars is rounded to the nearest million unless otherwise stated. Unless otherwise indicated, all financial information is presented in accordance with Canadian generally accepted accounting principles (GAAP). The Company uses adjusted EBITDA and adjusted funds from operations as financial performance measures, which are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP. For further discussion of such terms, see the Company's Management's Discussion and Analysis (MD&A) dated February 15, 2019 for the year ended December 31, 2018.

Certain capitalized terms used herein, and if not defined where first used, are defined under "Definitions of Certain Terms".

This AIF provides material information about the business and operations of Capital Power Corporation.

The "Risks and Risk Management" section of the Company's MD&A dated February 15, 2019 for the year ended December 31, 2018 is incorporated herein by reference and can be found on SEDAR at www.sedar.com.

FORWARD-LOOKING INFORMATION

Forward-looking information or statements included in this AIF are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this AIF is generally identified by words such as "will", "anticipate", "believe", "plan", "intend", "target", and "expect" or similar words that suggest future outcomes.

Forward-looking information in this AIF includes, among other things, information relating to: (i) expectations regarding the timing of, funding of, generation capacity of, costs for, technology selected for or commercial arrangements regarding existing, planned and potential development projects and acquisitions; (ii) expectations regarding revenues generated by existing facilities or facilities in development, including expected impacts to net income, adjusted EBITDA, net cash flows from operating activities and adjusted funds from operations; (iii) expectations regarding future growth and emerging opportunities in Capital Power's target markets including the focus on certain technologies; (iv) expectations regarding availability of fuel supply; (v) expectations regarding the timing or outcome of applications for permits or licenses, or other regulatory proceedings; (vi) the expected impact of the GHG Regulations and other regulations announced by the Government of Canada, the Climate Leadership Plan announced by the Government of Alberta and other environmental regulations on Capital Power's power plants, including compliance costs and the useful lives of power plants and any conversions; (vii) expectations regarding proposed new environmental regulations, including the timing of such regulations coming into force, and the impact of current and new environmental regulations on Capital Power's business, including, but not limited to, Capital Power's compliance costs; (viii) expectations regarding the timing for Capital Power to receive the majority of benefits from certain projects subject to tax equity financing arrangements; (ix) expectations regarding the timing of collective bargaining, or the timing, effect or implementation of collective agreements; (x) expectations regarding proposed REP procurement and new power market or energy resource regulations, such as the proposed capacity market in Alberta, including the timing of such regulations coming into force, and the impact of current and new power market or energy resource regulations on Capital Power; (xi) the timing, imposition and impact of taxes on Capital Power; (xii) expectations related to Capital Power's future cash requirements including interest and principal repayments, capital expenditures and dividends and distributions; (xiii) expectations for Capital Power's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings; (xiv) expectations regarding power requirements and demand in Capital Power's target markets; (xv) expectations around the line loss rule proceeding, including timing of retroactive loss factors being finalized, participation in the applicable appeal process and potential impacts to the Company; (xvi) expectations regarding Capital Power's intention to acquire Common Shares pursuant to its normal course issuer bid;

and (xvii) statements pertaining to PG&E's U.S. bankruptcy proceedings and management's assessment of the potential financial impact of the outcome of such proceedings on the Company.

These statements are based on certain assumptions and analyses made by the Company considering its experience and perception of historical trends, current conditions and expected future developments, and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity and other energy prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, and (v) effective tax rates.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to several known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties include: (i) power plant availability and performance including maintenance expenditures; (ii) changes in electricity prices in markets in which Capital Power operates; (iii) regulatory and political environments including changes to environmental, financial reporting, market structure and tax legislation; (iv) acquisitions and developments including timing and costs of regulatory approvals and construction; (v) ability to fund current and future capital and working capital needs; (vi) changes in energy commodity market prices and use of derivatives; (vii) changes in market prices and availability of fuel; (viii) changes in general economic and competitive conditions; and, (ix) the outcome of the line loss rule proceeding. See "Risks and Risk Management" in the Company's MD&A dated February 15, 2019 for the year ended December 31, 2018.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this AIF have the following meanings:

"**150 Mile House**" means the 150 Mile House waste heat facility as further described in "Business of Capital Power – Ontario and BC Contracted Plants – 150 Mile House"

"**ABCA**" *Business Corporations Act* of the Province of Alberta

"**AER**" means the Alberta Energy Regulator

"**AESO**" means the Alberta Electric System Operator

"**AIF**" means Annual Information Form

"**AISC**" means Air Issues Steering Committee, a committee of the Canadian Electricity Association, Generation Council

"**Arlington Valley**" means the Arlington Valley facility as further described in "Business of Capital Power – US Contracted Plants – Arlington Valley"

"**Ascend**" means Ascend Performance Materials LLC

"**ATCO**" means ATCO Power Canada Ltd.

"**AUC**" means the Alberta Utilities Commission

"**Balancing Pool**" means the Alberta Balancing Pool, an Alberta provincial government entity established to, among other things, hold certain PPAs

"**BC**" means the Province of British Columbia

"**BC Hydro**" means the British Columbia Hydro and Power Authority

"**BCUC**" means the British Columbia Utilities Commission

"**Beaufort**" means the Beaufort solar facility as further described in "Business of Capital Power – US Contracted Plants – Beaufort"

"**Bloom**" means the Bloom wind facility as further described in "Business of Capital Power – US Contracted Plants – Bloom"

"**Board**" means the board of directors of Capital Power Corporation

"**C2CNT**" means a company that has developed and is now applying at scale an innovative technology that captures and transforms carbon dioxide (CO_2) into a useful and high-value product called carbon nanotubes

"**CAISO**" means the California Independent System Operator

"**Capital Power**" means Capital Power Corporation together with its subsidiaries on a consolidated basis, including its interest in Capital Power L.P., except where otherwise noted or the context otherwise indicates

"**Cardinal Point**" means the Cardinal Point wind project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Cardinal Point"

"**CASA**" means the Clean Air Strategic Alliance, an Alberta multi-stakeholder partnership composed of representatives selected by industry, government and non-government organizations, committed to a comprehensive air quality management system for the province

"**CBCA**" means the *Canada Business Corporations Act*

"**CCIR**" means the Carbon Competitiveness Incentive Regulation (Alberta Regulation 255/2017) made pursuant to the *Climate Change and Emissions Management Act* of the Province of Alberta

"**CCS**" means carbon capture and storage

"**CGC&N**" means the Corporate Governance, Compensation and Nominating Committee of the Company

"**CGU**" means cash generating unit

"**Climate Leadership Plan**" means Alberta's Climate Leadership Plan announced by the Government of Alberta in November of 2015 which it described as a made-in-Alberta strategy to reduce carbon emissions while diversifying the economy and creating jobs. Key aspects of the plan include:

(i) implementing a new carbon tax on electricity generation;

(ii) retirement of coal-fired power plants in Alberta by 2030; and

(iii) the development of renewable power generation through competitive processes

"**Clover Bar**" means the Clover Bar Energy Centre as further described in "Business of Capital Power – Alberta Commercial Plants – Clover Bar"

"**CO_2**" means carbon dioxide

"**CO_2e**" means carbon dioxide equivalent

"**Common LP Units**" means common limited partnership units in the capital of the Partnership

"**Common Shares**" means common shares in the capital of Capital Power Corporation

"**COSIA**" means Canada's Oil Sands Innovation Alliance

"**CPC**" or the "**Company**" means Capital Power Corporation

"**CPLP**" or the "**Partnership**" means Capital Power L.P. and its subsidiaries on a consolidated basis, except where otherwise noted or the context otherwise indicates

"**CPLPGP**" means Capital Power GP Holdings Inc., the general partner of CPLP

"**CPLPHI**" means Capital Power LP Holdings Inc., a subsidiary of the Company and the limited partner of CPLP

"**CPLP Trust Indenture**" means the Trust Indenture dated April 14, 2010 between CPLP and Computershare Trust Company of Canada as supplemented and amended from time to time as further described in "Capital Structure – Debt Issuance"

"**CPM**" means commodity portfolio management

"**CPP**" means the Clean Power Plan released by the US EPA to regulate CO_2 for existing power plants under the US Clean Air Act

"**CTG units**" means coal to natural gas converted units

"**CTI**" means critical transmission infrastructure

"**DBRS**" means DBRS Limited

"**Decatur**" means the Decatur Energy Center as further described in "Business of Capital Power – US Contracted Plants – Decatur"

"**DRIP**" means dividend reinvestment plan

"**East Windsor**" means the East Windsor Cogeneration Centre as further described in "Business of Capital Power – Ontario and BC Contracted Plants – East Windsor"

"**EBITDA**" means earnings before interest, income tax, depreciation and amortization

"**ECCC**" means Environment and Climate Change Canada, the lead department of the Government of Canada for a wide range of environmental issues

"**Element Power**" means Element Power US, LLC

"**ENMAX**" means ENMAX Corporation collectively with its subsidiaries

"**EoUL**" means end of useful life

"**EPA**" means electricity purchase agreement or energy purchase agreement, as applicable

"**EPCOR**" means EPCOR Utilities Inc. collectively with its subsidiaries

"**EPDC**" means EPCOR Power Development Corporation

"**EPEA**" means the *Environmental Protection and Enhancement Act* of the Province of Alberta

"**ERCB**" means the Energy Resources Conservation Board, an agency established by the Province of Alberta

"**EUA**" means the *Electric Utilities Act* of the Province of Alberta

"**Exchangeable LP Units**" means exchangeable common limited partnership units in the capital of the Partnership

"**FERC**" means the Federal Energy Regulatory Commission of the United States of America

"**FIT**" means Feed-In-Tariff

"**FMCC**" means Ford Motor Company of Canada

"**FPA**" means the Federal Power Act of the United States of America

"**Framework**" means the Pan-Canadian Framework on Clean Growth and Climate Change

"**GAAP**" means generally accepted accounting principles

"**GE**" means General Electric Inc.

"**Genesee 1 & 2**" means, collectively, the Genesee 1 and Genesee 2 facilities as further described in "Business of Capital Power – Alberta Contracted Plants – Genesee 1 & 2"

"**Genesee 3**" means the Genesee 3 facility as further described in "Business of Capital Power – Alberta Commercial Plants – Genesee 3"

"**Genesee 4 & 5**" means the Genesee 4 and 5 facilities under development as described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Genesee 4 & 5"

"**GHG**" means greenhouse gases

"**GHG Regulations**" means the Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations (SOR/ 2012-167) made pursuant to the *Canadian Environmental Protection Act*, 1999

"**GP Units**" means general partnership units in the capital of the Partnership

"**GWh**" means gigawatt hour(s)

"**Halkirk**" means the Halkirk wind facility as further described in "Business of Capital Power – Alberta Commercial Plants – Halkirk"

"**HSE**" means health, safety and environment

"**HSE Policy**" means the Health, Safety and Environment Policy of the Company

"**IESO**" means Independent Electric System Operator

"**IPO**" means the July 2009 initial public offering by Capital Power Corporation of 21.75 million Common Shares at a price of $23.00 per share, pursuant to an underwriting agreement with a group of underwriters, for proceeds, net of underwriter and issue costs, of approximately $475 million

"**IPP**" means independent power producer

"**Island Generation**" means the Island Generation facility as further described in "Business of Capital Power – Ontario and BC Contracted Plants – Island Generation"

"**ISO**" means Independent System Operator

"**ISO-NE**" means the Independent System Operator for New England

"**Joffre**" means the Joffre cogeneration facility as further described in "Business of Capital Power – Alberta Commercial Plants – Joffre"

"**JV Amending Agreement**" means the agreement amending the Genesee Mine Joint Venture Agreement as further described in "General Development of the Business – 2017 – Company History – Amendment of the Genesee Coal Mine Joint Venture Agreement"

"**K2**" means the K2 wind facility as further described in "Business of Capital Power – Ontario and BC Contracted Plants – K2"

"**Kingsbridge 1**" means the Kingsbridge 1 wind facility as further described in "Business of Capital Power – Ontario and BC Contracted Plants – Kingsbridge 1"

"**Keephills 3**" means the Keephills 3 facility as further described in "Business of Capital Power – Alberta Commercial Plants – Keephills 3"

"**LNG**" means liquified natural gas

"**LFM**" means loss factor calculation methodology

"**Macho Springs**" means the Macho Springs wind facility as further described in "Business of Capital Power – US Contracted Plants – Macho Springs"

"**MD&A**" means Management's Discussion and Analysis

"**MSA**" means the Market Surveillance Administrator for the Province of Alberta

"**MTN**" means medium term note

"**MW**" means megawatt(s)

"**MWh**" means megawatt hour(s)

"**New Frontier**" means the New Frontier wind facility as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – New Frontier"

"**New Indenture**" means the Trust Indenture dated May 3, 2016 between CPC and Computershare Trust Company of Canada as further described in "Capital Structure – Debt Issuance"

"**NI 52-110**" means National Instrument 52-110 – *Audit Committees*

"**NO_2**" means nitrogen dioxide

"**NO_x**" means oxides of nitrogen

"**NOVA**" means Nova Chemicals Corporation

"**Pattern**" means Pattern Energy Group Inc.

"**PDN**" means the Port Dover and Nanticoke wind facility as further described in "Business of Capital Power – Ontario and BC Contracted Plants – Port Dover and Nanticoke"

"**PG&E**" means Pacific Gas and Electric Company

"**PMRU**" means Prairie Mines & Royalty ULC, a subsidiary of Westmoreland

"**PPA**" means power purchase agreement or power purchase arrangement, as applicable

"**Preferred Shares**" means all of the Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 7 Shares and Series 9 Shares that are issued and outstanding

"**QF**" means a qualifying facility and is a term used to describe a category of cogeneration or small power generating facility that meets certain ownership, operating, and efficiency criteria established by FERC pursuant to the US Public Utility Regulatory Policies Act of 1978 (see "Regulatory Overview – United States")

"**Quality**" means the Quality wind facility as further described in "Business of Capital Power – Ontario and BC Contracted Plants – Quality"

"**RECs**" means renewable energy credits

"**RTOs**" mean Regional Transmission Organizations

"**RESA**" means a Renewable Energy Support Agreement

"**REP**" means Alberta's Renewable Electricity Program being administered by the AESO that proposes to add 5,000 MW of renewable energy capacity by 2030

"**Reorganization**" means the series of transactions concurrent with the completion of the IPO pursuant to which CPLP acquired substantially all of the power generation assets of EPCOR, which transactions consisted of:

(i) the formation of CPLP by CPC, as the initial general partner with one GP Unit, and Capital Power LP Holdings Inc., a wholly-owned subsidiary of CPC, as the initial limited partner with one Common LP Unit;

(ii) the sale by EPCOR of all of the outstanding common shares of EMCC Limited to CPC in exchange for a cash payment of approximately $468 million out of the net proceeds of the IPO;

(iii) the contribution by EMCC Limited of substantially all of its assets to CPLP in exchange for 21.75 million GP Units of CPLP, and the acquisition by EMCC Limited of CPC's GP Unit in CPLP, pursuant to which EMCC Limited (subsequently re-named Capital Power GP Holdings Inc.) became the sole general partner of CPLP; and

(iv) the sale by EPDC of substantially all of its assets (consisting primarily of assets related to Genesee 1 & 2, the Genesee coal mine joint venture and certain interests in partnerships) to CPLP in return for 56.625 million Exchangeable LP Units of CPLP and approximately $896 million in cash (financed by CPLP by way of a long-term debt obligation to EPCOR (see "Material Contracts – Back-to-Back Credit Agreement")) and the concurrent subscription by EPDC for 56.625 million Special Voting Shares for a nominal amount and acquisition of the Special Limited Voting Share

"**Roxboro**" means the Roxboro facility as further described in "Business of Capital Power – US Contracted Plants"

"**Savona**" means the Savona waste heat facility as further described in "Business of Capital Power – Ontario and BC Contracted Plants – Savona"

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval, which can be accessed via the Internet at www.sedar.com

"**S&P**" means S&P Global Ratings, Inc.

"**Series 1 Shares**" means the cumulative rate reset preference shares, series 1 issued by the Company

"**Series 3 Shares**" means the cumulative rate reset preference shares, series 3 issued by the Company

"**Series 5 Shares**" means the cumulative rate reset preference shares, series 5 issued by the Company

"**Series 7 Shares**" means the cumulative minimum rate reset preference shares, series 7 issued by the Company

"**Series 9 Shares**" means the cumulative minimum rate reset preference shares, series 9 issued by the Company

"**SGER**" means the Specified Gas Emitters Regulation (Alberta Regulation 139/2007) made pursuant to the *Climate Change and Emissions Management Act* of the Province of Alberta

"**Shepard**" means the Shepard Energy Centre as further described in "Business of Capital Power – Alberta Commercial Plants – Shepard"

"**SO_2**" means sulphur dioxide

"**Southport**" means the Southport facility as further described in "Business of Capital Power – US Contracted Plants – Southport"

"**Special Voting Shares**" means the special voting shares that existed in the capital of Capital Power Corporation prior to being removed from its authorized capital effective on May 4, 2016, after such removal was approved by the Company's common shareholders in a special resolution on April 22, 2016

"**Special Limited Voting Share**" means the special limited voting share in the capital of Capital Power Corporation

"**SRDL**" means Siksika Resource Developments Limited

"**Sundance PPA**" means the PPA for Sundance under Section 45.95(1) of the *Electric Utilities Act* between TransAlta Utilities Corporation, as owner, and a subsidiary of the Company, as buyer, made in respect of Units 5 and 6 of the Sundance power plant owned by TransAlta, and as amended, restated or supplemented from time to time

"**Task Force on Climate-related Financial Disclosure**" or "**TCFD**" means the Task Force on Climate-related Financial Disclosure established by the Financial Stability Board, an international body that monitors and makes recommendations about the global financial system

"**TCM Rule**" means the AESO's Transmission Constraints Management Rule

"**TEI**" means tax equity investor partner

"**t/GWh**" means tonnes per gigawatt hour(s)

"**TransAlta**" means TransAlta Corporation and, where the context requires, TransAlta Corporation and/ or its subsidiaries

"**TransCanada**" means TransCanada Pipelines Limited

"**US**", "**U.S.**" or "**United States**" means the United States of America

"**US EPA**" means the United States Environmental Protection Agency

"**VaR**" means Value-at-Risk

"**Wells Fargo**" means Wells Fargo Bank, N.A.

"**Westmoreland**" means Westmoreland Coal Company

"**Whitla**" means the Whitla wind project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Whitla"

"**Whitla 1**" means Phase 1 of the Whitla wind project

"**York**" means the York Energy Centre as further described in "Business of Capital Power – Ontario and BC Contracted Plants – York"

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CORPORATE STRUCTURE

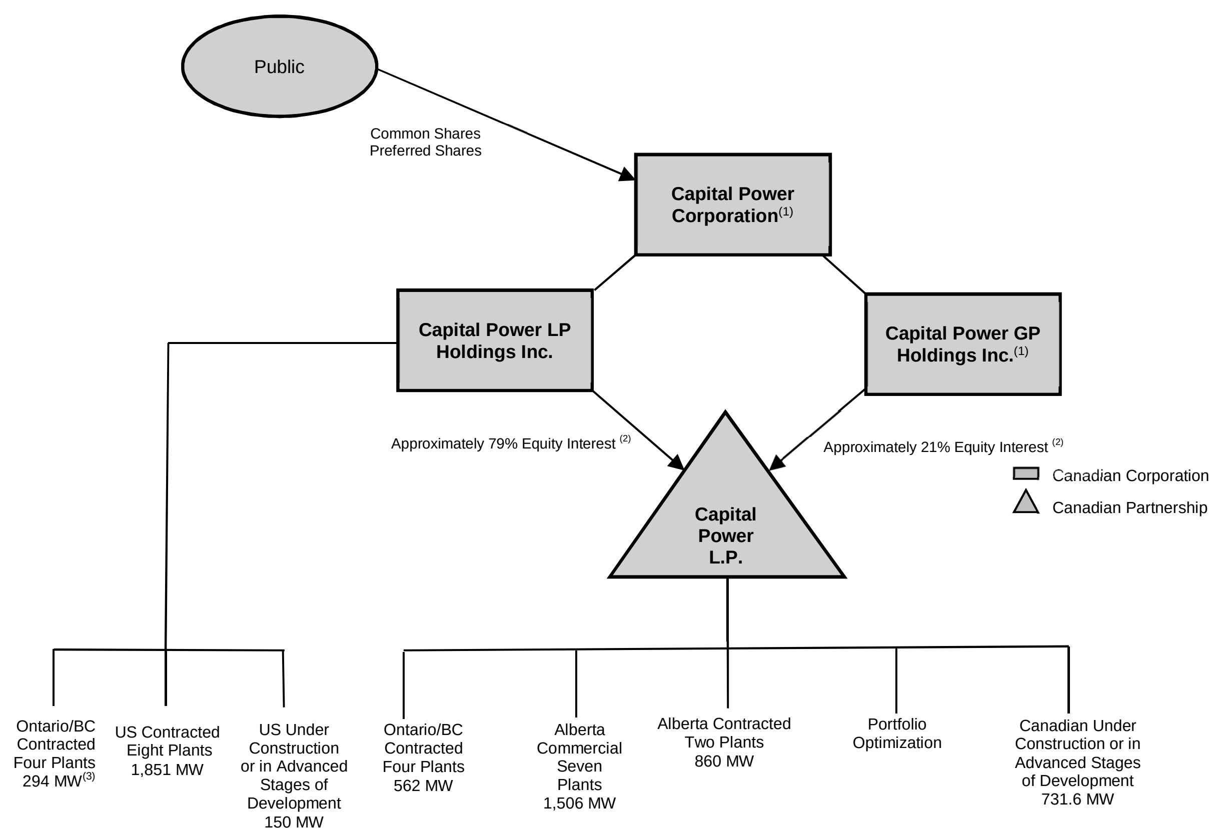
Capital Power Corporation

The Company was incorporated under the CBCA on May 1, 2009. The Company's articles were amended on May 6, 2009, June 16, 2009, July 7, 2009, December 10, 2010, December 14, 2012, March 11, 2013, May 4, 2016, September 28, 2016, and July 31, 2017 to, among other things, create the classes of shares described in this AIF. See "Capital Structure".

The principal business office and registered office of the Company is located at Suite 1200, 10423 – 101 Street NW, Edmonton, Alberta, Canada, T5H 0E9.

For a description of the Company's inter-corporate relationships with its subsidiaries, see "Corporation Structure – Inter-Corporate Relationships".

The following chart generally illustrates Capital Power's business and the inter-corporate relationships of the Company with its shareholders and with CPLP and CPLPHI, which directly and indirectly hold many of the Company's assets and investments in the electrical power generation business:



Notes:

(1) As at December 31, 2018, EPCOR held the one Special Limited Voting Share of the Company and the one special limited voting share of CPLPGP. See "Capital Structure".

(2) As at December 31, 2018, CPLPHI held all of the Common LP Units, and CPLPGP directly held all of the GP Units, of CPLP.

(3) East Windsor, Savona, 150 Mile House and Capital Power's 50% interest in York are held directly by Capital Power LP Holdings Inc. and indirectly by CPLPGP. Generally, see "Business of Capital Power – Generation Plant Summary" for details of the Company's generating facilities in each category.

Capital Power L.P.

CPLP is a limited partnership established under the laws of the Province of Ontario. The general partner of CPLP is CPLPGP which is wholly-owned by the Company (subject to the one special limited voting share of CPLPGP held by EPCOR) and is incorporated pursuant to the ABCA. Capital Power elects the board of directors of CPLPGP, the general partner of CPLP.

Capital Power indirectly holds all of the GP Units (subject to the one special limited voting share of CPLPGP held by EPCOR) and all of the Common LP Units, representing 100% of the total outstanding partnership interests in CPLP.

Inter-Corporate Relationships

The following table provides the name and the jurisdiction of incorporation, continuance, formation or organization of the subsidiaries of the Company other than those subsidiaries that, as at December 31, 2018, had aggregate total assets or revenues that did not exceed 20% of Capital Power's consolidated assets or consolidated revenues. Unless otherwise noted, the Company directly or indirectly owns 100% of the voting securities of the subsidiaries listed below, or of the general partner of those subsidiaries that are limited partnerships.

Subsidiaries	**Jurisdiction of Incorporation, Continuance, Formation or Organization**
Capital Power L.P.	Ontario
CP Energy Marketing L.P.	Alberta
Capital Power (Alberta) Limited Partnership	Alberta
Capital Power (K3) Limited Partnership	Alberta
CPI USA North Carolina LLC	Delaware
Decatur Energy Centre, LLC	Delaware
Halkirk I Wind Project LP	Alberta
Capital Power (PDN) L.P.	Ontario
Capital Power (G3) Limited Partnership	Alberta
CP Bloom Wind LLC	Delaware
Arlington Valley, LLC	Delaware
Capital Power LP Holdings Inc.	Canada
Meadowlark Wind I, LLC	Delaware

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Capital Power is a North American IPP headquartered in Edmonton, Alberta. Capital Power develops, acquires, owns and operates power generation from a range of energy sources. Its asset portfolio includes ownership in a number of operating facilities in Canada and the United States and projects in various stages of construction and development. The significant events and conditions that have influenced the general development of Capital Power's business over the past three years are summarized below. Certain of these events and conditions and operational information on Capital Power's plants are discussed in greater detail under the heading "Business of Capital Power".

Company History

2018

New Frontier Begins Commercial Operations

On January 9, 2019, the Company announced its New Frontier wind project, located in North Dakota, began commercial operation on December 21, 2018. The construction of the 99 MW facility was completed on-schedule and below its original cost estimate of approximately $182 million ($145 million).

In addition, on December 31, 2018, the Company received approximately $125 million (US$92 million) in net tax equity financing from an investment grade US financial institution in exchange for Class A interests of a subsidiary of the Company.

Capital Power will operate New Frontier under a 12-year fixed price contract. See "General Development of the Business – Company History – 2017 – Completion of Contract for Output of New Frontier" and "Business of Capital Power – US Contracted Plants – New Frontier".

Sale of Minority Interest in K2

On November 7, 2018, the Company announced that it entered into an agreement for the sale of its minority owned one-third interest of 90 megawatts (MW) in K2 to a consortium of investors led by Axium Infrastructure for $216 million. The transaction closed on December 31, 2018.

Acquisition of Arlington Valley

On September 6, 2018, the Company announced that it entered into an agreement to acquire 100% of the ownership interests in Arlington Valley, LLC, which owned the Arlington Valley facility, a 580 megawatt (MW) combined cycle natural gas generation facility. The Company acquired Arlington Valley from funds managed by Oaktree Capital Management, L.P. and its co-investors for $399 million (US$303 million) in total cash consideration, including preliminary working capital and other closing adjustments of $3 million (US$3 million). The transaction closed on November 30, 2018.

Arlington Valley sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under a tolling agreement during the summer months through 2025. Arlington Valley is adjacent to the Palo Verde hub allowing for additional capacity and energy to be sold into the DSW or CAISO wholesale markets during the months outside the summer tolling months.

The acquisition of Arlington Valley supports the Company's US growth strategy and fully meets the Company's investment criteria. Arlington Valley is a well-positioned asset in the attractive DSW power market with growing demand and a low investment risk environment. See "Business of Capital Power – US Contracted Plants – Arlington Valley".

Capital Power Invests in C2CNT

On May 29, 2018, Capital Power announced that it acquired an equity interest in C2CNT, a company that developed and is applying at scale an innovative technology that captures and transforms CO_2 into a useful and high-value product called carbon nanotubes.

This technology will take CO_2 from many sources including emissions from thermal power generation and other industrial processes and convert it into carbon nanotubes, which can be used in various industries.

The C2CNT technology was developed by a team of scientists, led by Professor Stuart Licht, at George Washington University. The technology uses electrolysis to separate carbon from oxygen. The carbon can then be repurposed into nanotubes, and the oxygen is available for other uses.

Dr. Licht and his team are among five finalists competing in the natural gas track of the NRG COSIA Carbon XPRIZE competition. As part of the XPRIZE competition, C2CNT will start testing their technology at demonstration scale at the Alberta Carbon Conversion Technology Centre located at the Shepard Energy Centre in Calgary that Capital Power co-owns with ENMAX. See also "Company History – 2017 – Shepard Chosen as Test Site for NRG COSIA Carbon XPRIZE" and "Business of Capital Power – Alberta Commercial Plants – Shepard".

Genesee Royalty Rate Agreement

During the second quarter, Capital Power entered into an agreement with Genesee Royalty Limited Partnership establishing a fixed royalty rate structure in place of the previous structure which was based on coal regulations from the 1980s. The new structure provides improved royalty cost certainty in the future. See also "Company History – 2017 – Amendment to Genesee Coal Mine Joint Venture Agreement" and "Business of Capital Power – Alberta Commercial Plants – Genesee 3".

Bloom Tax Equity Agreement Amendment

As part of the enactment of the U.S. Tax Cuts and Jobs Act of 2017 in the fourth quarter of 2017, and the resulting reduction in the U.S. Federal corporate tax rate (effective January 1, 2018), a change in tax law provision was triggered in the tax equity agreement for Bloom. As a result, in May of 2018, the Company re-negotiated certain commercial terms within that agreement. The re-negotiated terms resulted in an interest rate increase on the tax equity financing balance. As well, a one-time reduction to the tax equity financing balance by $44 million (US $33 million) was recorded relating to additional tax benefits used by the tax equity partner. The overall impact of the re-negotiated terms resulted in a one-time, noncash increase in net income after tax of $15 million (US $11 million). Under the re-negotiated agreement and considering the reduction in the U.S. Federal corporate tax rate, the Company has maintained its original expected returns for Bloom. See also "Company History – 2017 – Bloom Begins Commercial Operation" and "Business of Capital Power – US Contracted Plants – Bloom".

Completion of Contracts for Cardinal Point

On April 30, 2018, Capital Power announced that the construction of Cardinal Point would proceed once all applicable regulatory approvals were received. Cardinal Point is a 150 MW facility to be constructed in the McDonough and Warren Counties, Illinois, and is anticipated to cost between $289 million and $301 million (US$236 million to US$246 million). Commercial operation of the facility is expected in March of 2020. Capital Power will operate Cardinal Point under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. Under the contract, Capital Power will swap the market revenue of the facility's generation for a fixed price payment over the 12-year term. In addition, Cardinal Point has secured three 15-year, fixed-price contracts with three Illinois utilities for the sale and purchase of RECs generated by the facility. The REC and output contracts will secure long-term predictable revenues, allowing Cardinal Point to secure tax equity financing and provide Capital Power the opportunity to complete its third wind development project in the growing U.S. renewables market. See "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Cardinal Point".

2017

Whitla Awarded 20-year Contract by AESO in First Round of REP

Capital Power's Whitla 1 project, was selected by the AESO as one of three successful proponents in the first round of its REP, which attracted global participation. This was the first of the REP processes planned by the AESO to undertake to deliver new renewable electricity in support of the Government of Alberta's target of 30% renewables by 2030.

Whitla 1 will be a 201.6 MW wind facility located 45 kilometres southwest of Medicine Hat in the County of Forty Mile, Alberta. The Whitla project site has capacity for approximately 300 MW that can be developed in two phases.

Capital Power and the AESO executed a RESA for Whitla 1 in December 2017. The RESA establishes the terms under which Capital Power will be entitled to receive support payments for 20 years in exchange for providing the AESO with all renewable attributes generated Whitla 1. The support payments for the first round of the REP program were structured as a contract-for-differences, under which successful bidders will receive the bid price subject to performance obligations set out in the RESAs.

Whitla 1's target commercial operation date is expected in the fourth quarter of 2019.

Capital Power expects the construction cost for Whitla 1 to be between $315 million and $325 million. See "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Whitla".

Completion of Contract for Output of New Frontier

On August 30, 2017, Capital Power announced the construction of its New Frontier wind facility. New Frontier is a 99 MW facility in McHenry County, North Dakota, and cost approximately $182 million (US$145 million). Commercial operation of the facility commenced in December 2018 and the project secured net tax equity financing of $125 million (US$92 million) from an investment grade US financial institution on December 31, 2018. See "General Development of the Business – Company History – Recent Developments – 2018 – New Frontier Begins Commercial Operation".

The Company executed a contract with Vestas Wind Systems A/S on November 20, 2017 to supply 29 V126, 3.45 MW wind turbines. Capital Power will operate New Frontier under a 12-year fixed price contract with an investment grade financial institution covering 87% of the facility's output. Under the contract, Capital Power will swap the market revenue of the facility's generation for a fixed payment over the 12-year term. See "Business of Capital Power – US Contracted Plants – New Frontier".

Capital Power Siksika Resource Developments Partnership

On July 5, 2017, Capital Power and SRDL entered into an exclusive agreement to jointly develop power projects on the Siksika Nation reserve. The Siksika Nation is located approximately 100 km southeast of Calgary, Alberta, and controls one of the largest reserves in Canada comprising approximately 172,000 acres of land with solar, wind and gas projects potential. The location is attractive for the development of power plants given ample water and the existing transmission and distribution infrastructure.

Capital Power and SRDL expect to develop multiple power projects including both renewable and natural gas-fired technologies. The agreement contemplates Capital Power as the lead developer and operator with both SRDL and Capital Power taking joint ownership positions in projects. The projects are intended to foster economic development and provide socioeconomic benefits to the Siksika Nation and its members, including employment, business opportunities for Siksika Nation-owned companies, education, training and support for traditional language and cultural enrichment.

SRDL is a wholly-owned company of the Siksika Nation. It currently operates several enterprises on the Siksika Nation reserve. The Siksika Nation has approximately 6,000 members.

Bloom Begins Commercial Operation

On June 1, 2017, the Company's 178 MW Bloom wind facility commenced commercial operations. See "Business of Capital Power – US Contracted Plants – Bloom".

On June 12, 2017, the Company received $244 million (US$181 million) in financing from Goldman Sachs Alternative Energy Investing Group, an affiliate of Goldman Sachs, Inc. in exchange for Class A interests of the Bloom project entity, an indirect subsidiary of the Company. The Company incurred issue costs of $7 million (US$5 million) associated with the financing.

Effective July 1, 2017, Bloom will operate under a 10-year proxy revenue swap agreement with Allianz Risk Transfer, a subsidiary of Allianz SE. Under the contract, which was executed on April 21, 2016, Capital

Power swaps the market revenue of the project's generation for a fixed annual payment for a 10-year term. The agreement secures long-term predictable revenues and mitigates generation volume uncertainty.

Acquisition of Decatur

On April 12, 2017, Capital Power announced that it entered into an agreement to acquire all of the ownership interests in Decatur Power Holdings, LLC, which owns Decatur from an affiliate of LS Power Equity Partners III. On June 13, 2017, the Company completed the acquisition for $603 million (US$448 million), including working capital and other closing adjustments of $9 million (US$7 million). Decatur is a 795 MW natural gas-fired combined cycle power generation plant located in Decatur, Alabama that operates under a tolling agreement.

Decatur sells capacity to a regional entity under a 10-year contract that expires on December 31, 2022. Decatur is well-positioned, given anticipated market conditions, as well as significant remaining useful life, to be re-contracted or to pursue other commercial alternatives at the end of the current contract, including the ability to sell power into the Pennsylvania, New Jersey, and Maryland interconnection market starting in 2023.

The Decatur acquisition supports the Company's growth strategy and increases the Company's geographical diversification and contracted cash flows. See "Business of Capital Power – US Contracted Plants – Decatur".

Amendment of the Genesee Coal Mine Joint Venture Agreement

On March 28, 2017, the Company announced that it entered into an agreement to amend its Genesee Mine Joint Venture Agreement with PMRU, a subsidiary of Westmoreland, to accelerate the repayment of amounts it would otherwise have owed to PMRU during the term of the agreement and eliminate all future payments to PMRU relating to existing capital assets at the Genesee coal mine. Capital Power will continue to pay PMRU contracted mining fees for PMRU's ongoing operation of the Genesee coal mine.

By accelerating the $70 million repayment of capital expenditures to PMRU, the transaction will reduce Capital Power's cost of coal for the Genesee facilities, and enhance the Company's net income, adjusted EBITDA, net cash flows from operating activities and adjusted funds from operations. The operations of the Genesee coal mine are unchanged as a result of the JV Amending Agreement and the Company will continue to control the Genesee coal mine.

Coal for the Genesee facilities is supplied by the adjacent Genesee coal mine under a long-term, cost of service supply agreement. Prior to the JV Amending Agreement, Capital Power paid PMRU a fee to cover PMRU's depreciation expense and certain other costs, as well as provide a variable rate of return to PMRU. These fees paid to PMRU were included as part of Capital Power's cost of coal for operating the Genesee facilities and have been eliminated by the JV Amending Agreement. See "Business of Capital Power – Alberta Commercial Plants – Genesee 3".

On October 9, 2018, Westmoreland filed voluntary petitions for relief under chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas, Houston Division. Westmoreland's Canadian entities, including PMRU, were excluded from the voluntary petitions and no insolvency proceedings have been commenced in Canada.

Acquisition of Thermal Facilities of Veresen Inc.

On February 21, 2017, the Company announced that it had entered into an agreement to acquire the thermal power business of Veresen Inc. Under the terms of the agreement, the Company would acquire 284 MW of generation from two natural gas-fired facilities in Ontario consisting of a 100% equity interest in East Windsor and a 50% interest in York. The Company would also operate both facilities. The transaction would also include 10 MW of zero-emissions waste-heat generation at the Savona and 150 Mile House facilities located along Enbridge's Westcoast Energy gas pipeline in British Columbia.

On April 13, 2017, the Company completed the acquisition of East Windsor and York for a purchase price that consisted of: (i) $235 million in total cash consideration, including working capital and other closing adjustments of $12 million, and (ii) the assumption of $254 million of project level debt (proportionate basis at acquisition date net book value). See "Business of Capital Power – Ontario and BC Contracted Plants – East Windsor" and "– York".

On June 1, 2017, the Company completed the acquisition of Savona and 150 Mile House for a purchase price that consisted of: (i) $8 million of total cash consideration, including working capital and other closing adjustments of $3 million, and (ii) the assumption of $18 million of project level debt. On October 4, 2017, the project level debt was paid out and discharged. See "Business of Capital Power – Ontario and BC Contracted Plants – 150 Mile House" and "– Savona".

Shepard Chosen as Test Site for NRG COSIA Carbon XPRIZE

On February 3, 2017, Shepard was chosen as the test site for the natural gas track of the prestigious $20 million NRG COSIA Carbon XPRIZE, a global competition to develop breakthrough technologies that convert CO_2 into valuable products. Shepard hosts the Alberta Carbon Conversion Technology Centre, as well as provides the flue gas for testing during the NRG COSIA Carbon XPRIZE and for future innovators.

The Alberta Carbon Conversion Technology Centre is a collaboration between the governments of Canada and Alberta, COSIA, Shepard, InnoTech Alberta and academia. Its purpose is to accelerate CO_2 reduction, carbon utilization and value-added economic development by allowing companies to demonstrate new technologies in a full-scale production environment. Shepard will be the only operating natural gas-fuelled power plant in the world where multiple advanced carbon utilization technologies can be tested at scale.

<u>2016</u>

Off-Coal Agreement

On November 24, 2016 Capital Power announced it reached an agreement with the Government of Alberta relating to the 2030 phase-out of coal emissions. Under the agreement, as compensation for the capital that Capital Power invested in coal generating assets that will be stranded effective December 31, 2030, Capital Power is to receive cash payments from the Government of Alberta of $52.4 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. The Government of Alberta has conducted an audit on the calculation of net book values driving the compensation payments and has withheld $2 million from the 2017 payment. The Company is disputing the withholding but has reduced the amounts recorded related to the compensation stream to reflect the uncertainty around the withheld portion of the 2017 payment. This has resulted in a reduction of $1 million to the government compensation amount recorded in other income to $51 million for 2017. Capital Power is required to cease coal-fired emissions from Genesee 1, Genesee 2, Genesee 3 and Keephills 3 by the end of 2030. See "Environmental Regulation – Alberta – Climate Change Strategy". See also "General Development of the Business – Company History – 2015 – Changes to Alberta's Emissions Regulations and Review of Climate Change Policy".

Alberta Renewable Energy Procurement

On September 14, 2016, the Government of Alberta confirmed a firm target of achieving 30% of Alberta's electricity use by 2030 from renewable energy sources and announced that it would support 5,000 MW of additional renewable capacity to help achieve that target. The first competition for new renewable projects under the REP was held in 2017 and resulted in projects for approximately 600 MW of capacity being awarded RESAs, with projects to be online by the end of 2019. See "General Development of the Business – Company History – 2017 – Whitla Awarded 20-Year Contract by AESO in First Round of REP" and "Environmental Regulation – Alberta – Climate Change Strategy".

Alberta Electricity Market Design

On November 23, 2016, the Government of Alberta announced the transition of Alberta's electricity market from an energy-only market to a capacity market by 2021. The Government of Alberta has committed to ensuring that existing investments will be treated fairly, and that the new market framework will continue to promote a level playing field between existing and new capacity. The AESO was tasked with designing the new market and commenced stakeholder engagement to do so in 2017. Consultation continued throughout 2018 and the AESO is expected to file a rule package and application for approval with the AUC in early 2019. The first capacity auction is expected to occur in late 2019 for delivery in Q4 of 2021. For further updates see "Regulatory Overview – Alberta – Alberta Announcement of Transition to a Capacity Market".

Canadian Federal Regulation of Natural Gas Generation

On November 21, 2016, the Government of Canada announced its plan to phase-out traditional coal-fired electricity by 2030, and to establish emission standards for natural gas-fired turbines, including new boilers, existing boilers, and existing coal boilers converted to natural gas. Under the proposal, coal boilers that are converted to natural gas would be subject to an interim emissions standard that would apply for the earlier of 15 years, or 2045, after which time the units would be required to meet the emissions standards for new gas-fired generation.

In December 2018, the Government of Canada published the final amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations and the Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation the Canada Gazette, Part II. For further updates see "Environmental Regulation – Canadian Federal Government – Greenhouse Gas Regulation – Natural Gas Generation".

Termination of the Sundance C Power Purchase Arrangement

On March 24, 2016, Capital Power announced its intent to terminate its role as Buyer of the Sundance PPA. Capital Power exercised its right to terminate the Sundance PPA under the change in law provisions of the arrangement, following changes to the SGER that took effect in Alberta at the start of 2016.

On July 25, 2016, the Government of Alberta commenced legal action against Capital Power and the other PPA buyers that had exercised their respective rights to terminate their respective PPAs. The Government of Alberta was of the view that the change-in-law provisions of the PPAs, which purported to permit companies to return a PPA to the Balancing Pool if government action made a PPA unprofitable were created unlawfully and were therefore void in law.

On November 24, 2016, Capital Power and the Government of Alberta entered into a Settlement Agreement and Release pursuant to which it was agreed that, among other things, Capital Power had no further obligations and the Balancing Pool assumed all obligations of Buyer under the Sundance PPA, without exception or limitation.

BUSINESS OF CAPITAL POWER

Overview

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The company develops, acquires, owns, operates and optimizes power generation from a variety of energy sources.

Capital Power owns approximately 5,073 MW of power generation capacity, and currently has 881.6 MW under construction or in advanced stages of development.

As of December 31, 2018, Capital Power's power generation fleet had a capacity weighted average facility age of 14 years and is diversified across three Canadian provinces and six states in the US.

Capital Power owns approximately 2,366 MW of power generation capacity in Alberta, with ownership interests in eight facilities. Approximately 50% of the power generated by Capital Power's Alberta power plants in which Capital Power owns an interest is sold on a merchant, or non-contracted, basis into energy markets as part of Capital Power's portfolio optimization activities. See "Business of Capital Power – Portfolio Optimization".

Capital Power sells some of the power generated by its Alberta power plants and all of the power generated by its power plants outside of Alberta, on a contracted basis to arm's length third parties. See "Business of Capital Power – Alberta Contracted Plants", "Business of Capital Power – Ontario and BC Contracted Plants", and "Business of Capital Power – US Contracted Plants".

As part of its growth strategy, Capital Power continually seeks opportunities to acquire or develop contracted, larger scale, natural gas-fired and renewable power generation facilities in Alberta, the rest of Canada, and the US, and has focused its merchant power business on Alberta.

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Generation Plant Summary

The following table provides details of Capital Power's generation plants that are in service, under construction or in advanced stages of development:

Category	Plant Name and Location	Type of Generating Plant	Year Commissioned or Target Date	Plant Generation Capacity (MW)	Capital Power Interest (MW)
Alberta Commercial Plants	Keephills 3, Alberta(1)	Supercritical Coal	2011	516	258
	Genesee 3, Alberta(1)	Supercritical Coal	2005	516	258
	Joffre, Alberta	Gas-fired, combined cycle cogeneration	2001	480	192
	Clover Bar, Alberta	Natural gas-fired, simple cycle	Unit 1 - 2008 Unit 2 & 3 - 2009	43 200	43 200
	Clover Bar Landfill, Alberta	Land fill gas-fired	2005	5	5
	Halkirk, Alberta	Wind turbine	2012	150	150
	Shepard, Alberta	Natural gas-fired, combined cycle	2015	800	400
	Total Alberta Commercial Plants (2) (3)				**1,506**
Alberta Contracted Plants	Genesee 1 & 2, Alberta(1)	Coal-fired steam turbine	Genesee 1 - 1994 Genesee 2 - 1989	430 430	430 430
	Total Alberta Contracted Plants(2) (3)				**860**
Ontario and BC Contracted Plants	Kingsbridge 1, Ontario	Wind turbine	2001 & 2006	40	40
	Island Generation, BC	Natural gas-fired, combined cycle	2002	275	275
	150 Mile House, BC	Waste heat	2008	5	5
	Savona, BC	Waste heat	2008	5	5
	East Windsor, Ontario	Natural gas	2009	84	84
	Quality, BC	Wind turbine	2012	142	142
	York, Ontario	Natural gas	2012	400	200
	PDN, Ontario	Wind turbine	2013	105	105
	Total Ontario and BC Contracted Plants(2)				**856**
US Contracted Plants	Roxboro, North Carolina	Coal, tire-derived fuel and wood waste power facility	1987	46(4)	46

Category	Plant Name and Location	Type of Generating Plant	Year Commissioned or Target Date	Plant Generation Capacity (MW)	Capital Power Interest (MW)
	Southport, North Carolina	Coal, tire-derived fuel and wood waste combined heat and power facility	1987	88[4]	88
	Decatur, Alabama	Natural gas	2002	795	795
	Macho Springs, New Mexico	Wind turbine	2011	50	50
	Beaufort, North Carolina	Solar	2015	15	15
	Bloom, Kansas	Wind turbine	2017	178	178
	Arlington Valley, Arizona	Natural gas	2002	580	580
	New Frontier, North Dakota	Wind turbine	2018	99	99
	Total US Contracted Plants[2]				**1,851**
Plants Under Construction or in Advanced Stages of Development	Genesee 4 & 5[5], Alberta	Gas-fired, combined cycle	TBD	1,060	530
	Whitla 1, Alberta	Wind turbine	2019	201.6	201.6
	Cardinal Point, Illinois	Wind turbine	2020	150	150
	Total Under Construction or in Advanced Stages of Development				**881.6**
Total Capital Power[6]					**5,954.6**

Notes:

(1) MW noted are gross capacity. All others listed are net capacity.
(2) Represents Capital Power's owned capacity as at the date of this AIF.
(3) During the fourth quarter of 2016, management determined, based on a review of the nature of cash flows, that its Alberta assets should be combined as one CGU for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present plant results based on the Alberta Commercial and Alberta Contracted groupings through 2020.
(4) Generation capacity utilizing current blended fuel mixture (wood product, tire-derived product and coal) versus the nameplate capacity of 54 MW and 109 MW for Roxboro and Southport respectively.
(5) Capital Power will continue to maintain the Genesee 4 & 5 project optionality. Full notice to proceed is deferred until Alberta market structure certainty exists and future Alberta electricity demand requires the addition of new generation.
(6) Represents Capital Power's owned capacity, capacity under construction or in advanced stages of development as at the date of this AIF.

Revenue and Volume

The following table shows Capital Power's revenues from its generation business by category:

	Revenues and other income (unaudited $ millions)	
Category	**Twelve Months Ended December 31, 2018**	**Twelve Months Ended December 31, 2017**
Alberta commercial facilities	587	657
Alberta contracted plants	268	241
Ontario and BC contracted plants	157	146
US contracted plants	304	201
Corporate	58	63
Sub Total	1,374	1,308
Unrealized changes in fair value of commodity derivatives and emission credits	20	(162)
Total	**1,394**	**1,146**

The following table shows Capital Power's power generation volumes from its generation business by category:

	Electricity Generation (GWh)	
Category	**Twelve Months Ended December 31, 2018**	**Twelve Months Ended December 31, 2017**
Alberta commercial plants	8,502	7,372
Alberta contracted plants	6,227	6,435
Ontario and BC contracted plants	1,070	1,018
US contracted plants	4,430	2,369
Total (excluding Sundance PPA)	**20,229**	**17,194**

Alberta Commercial Plants

As of the date of this AIF, the Alberta commercial plants consist of ownership interests in seven facilities representing approximately 1,506 MW of power generation capacity. The facilities generate electricity from coal, natural gas, wind and landfill gas. The output of the Alberta plants is managed on a portfolio basis by Capital Power's commodity portfolio management group. Output from these plants is sold into the deregulated Alberta power market.

Capital Power seeks to maximize earnings from Alberta commercial plants by achieving high availability and production levels from the facilities and by actively managing the portfolio's commodity price exposure relative to market price views.

Keephills 3

Keephills 3 is a 516 MW supercritical coal power plant located west of Edmonton, Alberta, which was commissioned in September 2011. Keephills 3 is owned by Capital Power and TransAlta in a joint venture, and each has a 50% ownership interest. TransAlta operates Keephills 3 on behalf of the owners. Costs for Keephills 3 are equally shared by its owners. Keephills 3 uses supercritical technology to achieve greater fuel efficiency and lower CO_2, NO_x and SO_2 emissions per MW than conventional subcritical pulverized coal technologies.

Commercial Arrangement: Merchant Facility

Capital Power's share of Keephills 3 generation is managed as part of Capital Power's Alberta electricity portfolio optimization activities.

Fuel Supply

Coal required for Keephills 3 is supplied by the adjacent Highvale coal mine. The mine is Canada's largest surface strip coal mine, covering approximately 12,600 hectares. It is owned by TransAlta and operated by SunHills Mining Limited Partnership, a TransAlta subsidiary. The Highvale coal mine supplies coal to the Keephills 3 joint venture, to TransAlta's other two units at the Keephills site and to TransAlta's Sundance units. It is estimated that the Highvale coal mine contains sufficient recoverable reserves to supply Keephills 3's anticipated requirements for the life of the facility. TransAlta, as operator and manager of Keephills 3, is obligated to manage the fuel supply and provide coal to Keephills 3 under a coal supply agreement similar to that which exists under the Genesee 3 joint venture. Under the Keephills 3 coal supply agreement, the joint venture pays for a pro-rata share of the Highvale mine costs and has also committed to fund specific operating and capital costs incremental to the coal requirements of Keephills 3.

Genesee 3

Genesee 3 is a 516 MW supercritical coal power plant located adjacent to Genesee 1 & 2 near Warburg, Alberta, which was commissioned in 2005. Genesee 3 is owned by Capital Power and TransAlta in a joint venture, and each has a 50% ownership interest. Capital Power operates Genesee 3 on behalf of the owners. Costs for Genesee 3 are equally shared by its owners. Genesee 3 uses supercritical technology to achieve greater fuel efficiency and lower CO_2, NO_x and SO_2 emissions per MW than conventional subcritical pulverized coal technologies.

To comply with new CASA SO_2 emission limits, Genesee 3 reduced its SO_2 emissions from 0.76 tonnes per hour to 0.36 tonnes per hour by installing a dry sorbent injection (DSI) system. The DSI system injects hydrated lime into the flue gas stream where it captures and removes SO_2. The DSI system has proved successful in reducing Genesee's emissions below the required level.

Commercial Arrangement: Merchant Facility

Capital Power's share of Genesee 3 is managed as part of Capital Power's Alberta electricity portfolio optimization activities.

Fuel Supply

Coal required for the Genesee power plants is supplied by the adjacent Genesee coal mine. The coal is provided to the Genesee power plants under long-term, cost of service supply agreement with the Genesee coal mine, a 50/50 joint venture between Capital Power and PMRU. PMRU is the operator. Capital Power is also a party to various agreements with PMRU in relation to the operation of the Genesee coal mine. See "Company History – 2017 – Amendment of the Genesee Coal Mine Joint Venture Agreement".

In 2014 and 2015, Capital Power received approval from the AER to add approximately 10,000 acres of surface land holdings as well as amended Alberta *Water Act* approvals for the Genesee coal mine. Capital Power believes the recoverable coal reserves to which it holds the rights exceed the estimated requirements for the life of Genesee 1, 2 and 3. The explored portions of the coal rights held by the Genesee coal mine joint venture are surface mineable, which reduces extraction costs.

Joffre

Joffre is a 480 MW natural gas combined-cycle cogeneration power plant located at NOVA's petrochemical complex near Red Deer, Alberta. Joffre began commercial operations in May 2001. Joffre is owned by Capital Power, ATCO and NOVA in a joint venture, with ownership interests of 40%, 40% and 20%, respectively.

The plant produces both steam and electricity for NOVA's host petrochemical complex. On average, 125 MW of the net electricity output of the cogeneration plant is required on site by the host petrochemical complex with the balance being sold to the wholesale electricity market. ATCO operates the plant and dispatches the power that is surplus to the needs of the host petrochemical complex for sale to the Alberta Power Pool on behalf of the owners.

Commercial Arrangement: Energy Supply Agreement and Merchant Facility

An energy supply agreement dated June 30, 1999 among a subsidiary of Capital Power, ATCO and NOVA sets forth the terms regarding the sale of electricity, steam and feedwater to NOVA. NOVA makes cost-of-service payments comprised primarily of a natural gas fuel cost payment, an operating and maintenance payment, and a capital payment calculated on a return-on-rate basis. The uncommitted capacity of the plant is bid into the wholesale electricity market by ATCO and Capital Power's share of output is incorporated into the Alberta electricity portfolio optimization activities. The agreement terminates upon decommissioning of the site by NOVA.

Fuel Supply

Capital Power procures and manages its 40% ownership share of the fuel for the facility. Any cost for fuel procured for generation required by the host petrochemical complex is passed through at cost to NOVA. Natural gas transportation agreements with TransCanada provide firm and interruptible transport services to the Joffre site.

Clover Bar

Clover Bar is a 243 MW natural gas power plant located in Edmonton, Alberta. Clover Bar is comprised of a GE LM 6000 natural gas-fired turbine with a generation capacity of approximately 43 MW, which began commercial operations in March 2008, and two GE LMS 100 natural gas-fired turbines with a combined generation capacity of approximately 200 MW, which began commercial operations in 2009. The turbines are simple cycle units with quick-start capability to meet the need for peaking capacity in Alberta.

Capital Power received approval under EPEA for the renewal of Clover Bar's operating permit on January 31, 2017. The EPEA approval has a life of ten years.

Commercial Arrangement: Merchant Facility

The units are dispatched to take advantage of price volatility in the Alberta electricity market and to provide ancillary services and, as such, are part of Capital Power's Alberta electricity portfolio optimization activities.

Fuel Supply

Natural gas for Clover Bar is purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada provides firm transport service to the Clover Bar site for a majority of the capacity.

Halkirk

Halkirk is a 150 MW wind facility located near Halkirk, Alberta, that began commercial operations on December 1, 2012. Halkirk is comprised of 83 Vestas V-90 turbines each with a generation capacity of 1.8 MW.

Commercial Arrangement: Merchant Facility

The electricity generated by Halkirk is managed as part of Capital Power's Alberta electricity portfolio optimization activities. RECs produced by Halkirk are sold to PG&E under the terms of a 20-year fixed price agreement. On January 29, 2019, PG&E filed for voluntary reorganization proceedings under chapter 11 of the U.S. Bankruptcy Code in California and subsequently had its credit rating downgraded to "D", representing default. In conjunction with the filings, PG&E also filed a motion seeking interim and final approval of the court to enter into an agreement for $5.5 billion in debtor-in-possession (DIP) financing with a group of lenders. PG&E is in the midst of political and regulatory pressure as well as uncertainty resulting from claims against PG&E related to wildfires that occurred in 2017 and 2018. At this time, PG&E has continued to fulfill its obligations to the Company under the fixed price agreement. As PG&E's bankruptcy proceeds, the Company will continue to monitor the situation. If at some point, PG&E is no longer able to fulfill its obligations under the fixed price agreement, the Company would have to pursue replacement contracts which may not be replaceable on similar terms to the existing contract.

Shepard

Shepard is an 800 MW natural gas fired combined-cycle power plant located in Calgary, Alberta, that began commercial operations in March, 2015. Shepard is owned by Capital Power and ENMAX in a joint venture, and each has a 50% interest. Shepard features combined-cycle technology that has two combustion turbines to generate electricity and makes use of waste heat through a steam turbine for further electricity production. This configuration makes Shepard's gas-fuelled facility one of the cleanest and most efficient combined cycle facilities in Alberta. Compared to a conventional coal plant, Shepard is approximately 30% more efficient, emits less than half the CO_2 equivalent per MWh and releases fewer carbon monoxide, SO_2, and NO_2 gases.

Commercial Arrangement: Merchant Facility

Capital Power and ENMAX have also entered into various commercial agreements including a 20-year tolling agreement that took effect April 1, 2015. Under the terms of the tolling agreement, ENMAX will pay Capital Power a fixed capacity charge for 50% of Capital Power's owned capacity from April 2019 to 2035. The remaining non-tolled portion of Capital Power's share of Shepard's generation is managed as part of Capital Power's Alberta electricity portfolio optimization activities.

Fuel Supply

Natural gas for Shepard is purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada provides firm transport service to the Shepard site. Capital Power is required to procure natural gas for Capital Power's non-tolled capacity.

Additional Alberta Facilities

Capital Power has a 100% interest in Clover Bar Landfill Gas Plant, an approximately 5 MW facility located in Edmonton, Alberta. The gas collection system was commissioned in 1992 to provide gas to the process plant for cleaning and flaring. The flaring creates carbon offset credits through the collection and combustion of methane. The generation facility was added to the gas processing facility in 2005, commissioned in 2005 and uses the cleaned gas from the process facility for its fuel source. The facility is one of Capital Power's carbon offset projects. Electrical output from the facility is sold into the Alberta wholesale electricity market at spot price.

Alberta Contracted Plants

Genesee 1 & 2

The Alberta contracted plants, consisting of Genesee 1 & 2, are coal-fired power plants with 860 MW of combined generation capacity located west of Edmonton near Warburg, Alberta. Both units are 100% owned and operated by Capital Power, and are located on land owned by Capital Power. Genesee 1 & 2 were commissioned in 1994 and 1989, respectively.

Commercial Arrangement: Power Purchase Arrangement

Genesee 1 & 2 are subject to a PPA with the Balancing Pool, which is in effect until December 31, 2020. Under the terms of the PPA, the Balancing Pool is entitled to the power produced by Genesee 1 & 2, up to their committed capacity. Generation in excess of committed capacity is managed as part of Capital Power's Alberta electricity portfolio optimization activities.

Fuel Supply

See "Business of Capital Power – Alberta Commercial Plants – Genesee 3 – Fuel Supply".

Ontario and BC Contracted Plants

The Ontario and BC contracted plants consist of generation facilities for which Capital Power sells all output of the facilities to provincial government entities, either the Ontario IESO or BC Hydro, as applicable, pursuant to long-term contracts. The Ontario and BC contracted plants consist of ownership interests in eight facilities representing approximately 856 MW of power generation capacity. The facilities generate electricity from natural gas, wind and waste heat.

Kingsbridge 1

Kingsbridge 1 is a 40 MW wind facility located in the Township of Ashfield-Colborne-Wawanosh, Ontario. Kingsbridge 1 consists of one Vestas V-90 turbine with a generation capacity of 1.8 MW commissioned in 2013, 21 Vestas V-80 turbines each with a generation capacity of 1.8 MW commissioned in 2006 and one Vestas V-47 turbine with a generation capacity of 0.7 MW commissioned in 2001.

Commercial Arrangement: Energy Supply Contracts

Kingsbridge 1 operates under the terms of two energy supply contracts with the Ontario IESO. The energy supply contract for the turbine commissioned in 2001 is a standard offer agreement under the Ontario IESO's Renewable Energy Standard Offer Program which terminates in March 2027. The energy supply contract for the remaining turbines terminates in March 2026.

Island Generation

Island Generation is a 275 MW natural gas combined-cycle power plant located at Campbell River, BC, that was commissioned in 2002 and acquired by Capital Power in October 2010. The facility is comprised of a GE GT24B gas turbine and a GE steam turbine.

Commercial Arrangement: Electricity Purchase Agreement

Island Generation is fully contracted to April 2022 under a tolling arrangement with BC Hydro. BC Hydro has full dispatch rights and is responsible for the fuel supply to the facility.

150 Mile House

150 Mile House is a 5 MW waste heat facility located at a gas pipeline compressor station near 150 Mile House, British Columbia owned by Westcoast Energy Inc., a subsidiary of Enbridge. Enbridge operates the facility. The facility began commercial operation in 2008.

Commercial Arrangement: Electricity Purchase Agreement

The facility operates under a 20-year EPA with BC Hydro, with original terms expiring in 2028.

Savona

Savona is a 5 MW waste heat facility located at gas pipeline compressor station near Savona, British Columbia owned by Westcoast Energy Inc., a subsidiary of Enbridge. Enbridge operates the facility. The facility began commercial operation in 2008.

Commercial Arrangement: Electricity Purchase Agreement

The facility operates under a 20-year Electricity Purchase Agreement with BC Hydro, with original terms expiring in 2028.

East Windsor

East Windsor is an 84 MW natural gas facility located in Windsor, Ontario. The project encompasses approximately 1.5 acres of industrial land, located adjacent to the existing powerhouse owned by FMCC and is equipped with modern emission controls that meet all federal and provincial air quality standards. The facility began commercial operation in 2009.

Commercial Arrangement: Electricity Purchase Agreement

The facility is fully contracted with the Ontario IESO until 2029 and has a long-term steam agreement to supply FMCC's Windsor engine plant.

Fuel Supply

Capital Power procures and delivers the fuel for the facility, the cost for which is passed through to the Ontario IESO. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas, the majority of costs for which are passed through to the Ontario IESO.

Quality

Quality is a 142 MW wind facility located near Tumbler Ridge, BC that began commercial operations in November 2012. Quality is comprised of 35 Vestas V-90 turbines each with a generation capacity of 1.8 MW and 44 Vestas V-100 turbines each with a generation capacity of 1.8 MW.

Commercial Arrangement: Electricity Purchase Agreement

Quality has a 25-year EPA with BC Hydro.

York

York is a 400 MW natural gas facility located northwest of Newmarket, Ontario in the Township of King. This facility is the largest quick-response gas-fired peaking plant in Ontario. The facility provides power during periods of peak demand.

The facility is jointly owned, with Capital Power having a 50% interest.

Commercial Arrangement: Peaking Generation Contract

The facility is fully contracted with the Ontario IESO until 2032.

Fuel Supply

Capital Power procures and delivers the fuel for the facility for which the cost of fuel is passed through to the Ontario IESO. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas, the majority of costs for which are passed through to the Ontario IESO.

PDN

PDN is a 105 MW wind facility located in the counties of Norfolk and Haldimand, Ontario that began commercial operations in November 2013. The facility is comprised of 58 Vestas V-90 turbines each with a generation capacity of 1.8 MW.

Commercial Arrangement: Electricity Purchase Agreement

PDN has a 20-year PPA with the Ontario IESO which expires in 2023.

US Contracted Plants

Roxboro

Roxboro, a 46 MW biomass power plant located in Roxboro, North Carolina, was commissioned in 1987 and acquired by Capital Power in conjunction with the Capital Power Income L.P. divestiture in November 2011. Particulate emissions are controlled using engineered fabric filters, which capture particulate matter in order to comply with state and federal environmental regulations.

Commercial Arrangement: Power Purchase Agreement

Roxboro sells all of its electrical output under a PPA with Carolina Power & Light Company doing business as Progress Energy Carolinas, Inc., a subsidiary of Duke Energy Corporation that expires at the end of March 2021.

Commercial Arrangement: REC

Roxboro has a 10-year fixed price agreement with Duke Energy Progress to sell RECs generated from tire-derived fuel and wood biomass. The agreement expires at the end of March 2021.

Fuel Supply

Roxboro's fuel requirements are satisfied with a mixture of wood residuals, tire-derived fuel and a small amount of coal. Coal is sourced from regional coal suppliers; tire-derived fuel and wood residuals are sourced from multiple local suppliers. Capital Power has a contract with Central Carolina Holdings LLC for 60% of the tire-derived fuel requirements of both Roxboro and Southport. Tire-derived fuel receives an additional REC when purchased from Virginia. Wood residuals are procured at fixed prices indexed to the distance from the facility and are subject to a fuel charge.

Southport

Southport, an 88 MW biomass cogeneration heat and power plant located in Southport, North Carolina, was commissioned in 1987 and acquired by Capital Power in November 2011. Particulate emissions are controlled using engineered fabric filters, which capture particulate matter in order to comply with state and federal environmental regulations.

Commercial Arrangement: Power Purchase Agreement

Southport provides all of its electrical output under a PPA with Carolina Power & Light Company doing business as Progress Energy Carolinas, Inc., a subsidiary of Duke Energy Corporation that expires at the end of March 2021. Southport also sells steam to Archer Daniels Midland Company pursuant to a contract that expires at the end of March 2021.

Commercial Arrangement: REC

Southport has a 10-year fixed price agreement in place with Duke Energy Progress for RECs generated from tire-derived fuel and biomass. The plant also has a steam supply contract with a nearby Archer Daniels Midland facility to provide varying amounts of 150 psig process steam. Southport also has 10-year fixed price thermal REC agreement in place with Duke Energy Corporation. These agreements expire at the end of March 2021.

Fuel Supply

Southport's fuel requirements are satisfied with a mixture of wood residuals, including green wood and rail ties, tire-derived fuel and a small amount of coal. Coal is sourced from regional coal suppliers; tire-derived fuel and wood residuals are sourced from multiple local suppliers. Capital Power has a contract with Central Carolina Holdings LLC for 60% of the tire-derived fuel requirements of both Southport and Roxboro. Tire-derived fuel receives an additional REC when purchased from Virginia. Wood residuals are procured at fixed prices indexed to the distance from the facility and subject to a fuel charge.

Decatur

Decatur is a 795 MW natural gas-fired combined cycle power generation plant located in Decatur, Alabama, that Capital Power acquired on June 13, 2017. The plant is a 3X1 combined cycle facility comprised of three Siemens SGT6-5000FD2 combustion turbine generators, three Nooter Eriksen heat recovery steam generators, and a single Toshiba steam turbine generator. Emissions are controlled through selective catalytic reduction and a dry-low NO_x combustion system.

The facility is located on property owned by Ascend and there is an agreement in place to provide demineralized water to Ascend.

Commercial Arrangement: Conversion Services Agreement

Decatur operates under a tolling agreement with a regional entity and is fully contracted until the end of 2022.

Fuel Supply

Fuel procurement and delivery are the responsibility of the tolling agreement counterparty.

Macho Springs

Macho Springs is a 50 MW wind facility located in Luna County, New Mexico, that began commercial operations in November 2011 and was acquired by Capital Power in December 2014. The facility is comprised of 28 Vestas V-100 turbines each with a generation capacity of 1.8 MW. MetLife Capital, Limited Partnership is both a TEI and non-recourse term loan provider to Macho Springs. The TEI received the majority of the earnings, tax benefits and cash flows from Macho Springs until it reached its target yield, after which time the project reverted such that Capital Power receives the majority of the earnings, tax benefits, and cash flows. The reversion occurred on September 30, 2018, and is subject to a potential true-up after year end pursuant to the terms of the agreement.

Commercial Arrangement: Electricity Purchase Agreement

Macho Springs has a 20-year PPA with Tucson Electric Power which expires November 15, 2031.

Beaufort

Beaufort is a 15 MW photovoltaic solar facility located near Chocowinity, Beaufort County, North Carolina, that began commercial operations December 2015. The project entered into a sale-leaseback transaction with Wells Fargo to monetize the state and federal investment tax credits for which it is eligible. Under the transaction, Wells Fargo purchased the project's equipment, and leases it back to Beaufort, LLC for ten years. At the conclusion of the lease, Capital Power has the option to re-purchase the project for fair market value.

Commercial Arrangement: Electricity Purchase Agreement

Beaufort has a 15-year PPA with Duke Energy Progress, LLC which expires December 22, 2030.

Bloom

Bloom is a 178 MW wind facility consisting of 54 Vestas V117-3.3 MW turbines. Bloom is located on 15,000 acres of privately owned lands approximately 20 miles south of Dodge City in Ford and Clark Counties, Kansas.

Commercial Arrangement: Swap Arrangement

Capital Power owns and operates Bloom under a 10-year, fixed revenue contract with Allianz Risk Transfer a subsidiary of Allianz SE, covering 100% of the facility's output. Under the contract, Capital Power swaps the market revenue of the facility's generation for a fixed annual payment until April 2026. In addition, the project secured tax equity financing from Goldman Sachs Alternative Energy Investing Group as TEI, which funded an initial 65% of Bloom costs when the facility achieved commercial operation in June 2017. The TEI will receive the majority of the tax benefits and approximately 33% of cash distributions until it has reached its target yield, after which time the project will revert so that Capital Power will receive the majority of the tax benefits and cash flows.

Arlington Valley

Arlington Valley is a 580 megawatt (MW) combined cycle natural gas generation facility located approximately 50 miles southwest of Phoenix, Arizona. The facility was commissioned in 2002 and acquired in late 2018.

Commercial Agreement: Tolling Agreements

Arlington Valley sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under a tolling agreement during the summer months through 2025. For the non-summer months through 2025, Arlington Valley is actively negotiating with several trading firms to sell capacity and electricity under a Heat Rate Call Option. Arlington Valley is adjacent to the Palo Verde hub allowing for additional capacity and energy to be sold into the DSW or the CAISO wholesale markets during the months outside the summer tolling months.

New Frontier

New Frontier is a 99 MW greenfield wind project in McHenry County, North Dakota. It is located approximately 25 miles southeast of Minot. The facility consists of 29 Vestas V126-3.45MW wind turbines on 87-meter towers. The project was acquired in late 2014 as part of the Element Power portfolio and commenced commercial operation in December 2018. In addition, the project secured net tax equity financing of $125 million (US$92 million) from an investment grade US financial institution on December 31, 2018.

Commercial Arrangement: Electricity Purchase Agreement

Meadowlark Wind I LLC, the New Frontier project company, entered into a fixed price, fixed volume hedge agreement with an investment grade U.S. financial institution to sell approximately 87% of its output. The hedge swaps the variable revenues received at the project's injection node for a fixed price for a fixed notional quantity of energy from an investment grade U.S. financial institution at the MISO Minnesota Hub. The hedge has a twelve-year term and begins on March 1, 2019. The remainder of the output is sold on a merchant, or non-contracted, basis.

Projects Under Construction or in Advanced Stages of Development

As of the date of this AIF, the following projects are under construction or in advanced stages of development:

Genesee 4 & 5

In April 2014, Capital Power and ENMAX executed an agreement to jointly develop, construct, and operate the Genesee 4 & 5 power project. The joint arrangement agreement provides for, among other things, an agreement for ENMAX to purchase approximately 250 MW from Capital Power under a tolling agreement for eight years.

The project has received all major regulatory approvals required to proceed to the construction phase and Capital Power's Board has approved the project. From 2015 to 2017, limited construction activities took place, but full notice to proceed was deferred until Alberta market structure certainty exists and future Alberta electricity demand requires the addition of new generation. The Genesee 4 & 5 project remains well-positioned to supply Alberta's future electricity needs.

Capital Power and ENMAX have executed agreements with Mitsubishi Hitachi Power Systems for the supply and maintenance of natural gas turbines for the project. The facility will have a nominal generation capacity of 1,060 MW consisting of two 530 MW one-on-one, single shaft power islands, each incorporating a 501 J-class natural gas turbine, steam turbine, generator and heat recovery steam generator. Construction for the project will be done in two, approximately equal, phases and will help replace generation from the retirement of coal-fired units in Alberta. Capital Power would lead the construction of the project and would be the operator of the facility. Genesee 4 & 5 would be built within the boundaries of the existing Genesee site, which is owned by Capital Power, and immediately adjacent to the Genesee 3 facility, which allows for usage of existing cooling pond and site infrastructure.

The capital cost for the project, excluding interest to fund construction and refundable transmission system contribution payments, is expected to be approximately $1.4 billion. ENMAX will seek required approvals to continue its 50% interest prior to full notice to proceed.

Whitla

Whitla is a fully permitted 300 MW wind development in the County of Fort Mile, Alberta. It will be constructed in two phases. Phase 1 of the Whitla development ("**Whitla 1**") is a 201.6 MW wind facility currently under construction. It is comprised of 56 turbines (56 Vestas V136 3.6 MW turbines). Whitla 1 is scheduled to achieve a commercial operation date by December 1, 2019. Phase 2 of Whitla ("**Whitla 2**") is a 97.2 MW facility with a target in-service date of Q4 2021.

Commercial Arrangement: Electricity Purchase Agreement

A RESA for Whitla 1 was executed on December 13, 2017 with the AESO that establishes the terms and conditions upon which Capital Power will be entitled to receive energy support payments for 20 years and will provide the AESO with all renewable attributes generated by Whitla 1. The RESA stipulates, among other detailed operational and commercial provisions, that Whitla 1 must meet a commercial operation date of December 1, 2019.

Cardinal Point

Cardinal Point is a 150 MW facility to be constructed in the McDonough and Warren Counties, Illinois, and is anticipated to cost between $289 million and $301 million (US$236 million to US$246 million). Commercial operation of the facility is expected in March of 2020.

Commercial Arrangement: Swap Agreement

Capital Power will operate Cardinal Point under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. Under the contract, Capital Power will swap the market revenue of the facility's generation for a fixed price payment over a 12-year term. In addition, the Cardinal Point project has secured 15-year, fixed-price Renewable Energy Credit (REC) contracts with three Illinois utilities. The remainder of the output is sold on a merchant, or non-contracted, basis.

<u>Portfolio Optimization</u>

Capital Power's commodity portfolio is comprised of exposures resulting from ownership of generation assets or financial interest in generation assets as well as transactions with other market participants. These exposures include electricity, natural gas and environmental commodities. All commodity risk management and optimization activities are centrally managed by Capital Power's CPM group. Portfolio optimization includes activities undertaken to both manage Capital Power's exposure to commodity risk and enhance earnings. Overall commodity exposure within the portfolio is managed within limits established under Capital Power's risk management policies and procedures.

Capital Power manages output from its commercial plants, contracted plants with residual commodity exposure and any acquired PPAs on a portfolio basis. Capital Power transacts physical and financial forward contracts that are generally non-unit specific, reducing exposure to plant specific operating characteristics. Capital Power also takes specific and limited positions in the natural gas and environmental commodities markets outside of Alberta to manage portfolio risk and develop and maintain capability to support Capital Power's growth strategy and to a lesser extent generate profits.

The CPM team:

- manages price and volume risk in Capital Power's commodity portfolio;
- sets generation unit offer strategy for electricity and ancillary services;
- acquires and schedules delivery of natural gas supply used to generate electricity; and
- ensures compliance with existing and emerging market based environmental regulations by transacting in environmental commodities markets to proactively manage compliance risks and costs.

Capital Power controls its commodity management and optimization activities by measuring and reporting commodity portfolio risk and validating transactions. Capital Power uses mark-to-market valuation and VaR techniques to assess the risk of its commodity portfolio. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between exposures. This technique utilizes historical data and back testing to assess market risk arising from possible future changes in commodity prices. In addition, Capital Power subjects the portfolio to stress testing by using pre-defined scenarios to estimate maximum potential losses under abnormal market conditions.

Competitive Environment

Capital Power typically competes with other IPPs and hybrid utilities (utilities with a merchant division) in the energy and environmental commodities markets.

In addition to these competitor types, Capital Power competes for asset acquisitions with public and private investors and financial intermediaries, such as private equity investors, hedge funds and infrastructure funds.

Capital Power's competitive environment is determined in large part by the types of power markets in which it operates. Capital Power has generation assets in the Alberta deregulated wholesale power market and in regulated and deregulated wholesale power markets in BC, Ontario, North Carolina, Alabama, Kansas, New Mexico, North Dakota and Arizona. For an overview of the structure of these markets, see "Regulatory Overview".

In deregulated wholesale markets, Capital Power competes with other power producers by leveraging its operational excellence, enabling it to offer energy, capacity and ancillary services into the market at a competitive price and with high availability. Capital Power also competes for long-term PPAs, offtakes, tolls, hedges, etc., to supply credit-worthy counterparties.

Within Alberta, between its merchant generation facilities and the generation it controls through joint venture agreements, Capital Power controls dispatchable merchant generation capacity in Alberta representing approximately 6.3% of the market.

In regulated and centrally-planned markets such as Ontario, Capital Power competes for long-term PPAs to supply credit-worthy counterparties, typically the incumbent utility or a government agency by: (i) developing projects that meet counterparty requirements (for generation type, location and capacity); (ii) securing suitable sites; and (iii) focusing on being a low-cost developer and efficient operator. Capital Power also competes to acquire contracted assets or development projects. Capital Power expects to compete for contracted opportunities across Canada and the US.

Environmental Regulation

Many of Capital Power's operations are subject to extensive federal, provincial, and state laws, regulations and guidelines relating to the generation of electricity, protection of the environment, and the health and safety of employees. These laws, regulations and guidelines apply to air emissions, water usage, wastewater discharges, wildlife and habitat protection, hazardous material handling, the storage, treatment, and disposal of waste and other materials, and remediation of sites and land-use responsibility.

Capital Power's thermal assets are emitters of various air pollutants including CO_2, NO_x, SO_2, mercury, and particulate matter. Capital Power is required to comply with all licenses and permits and federal, provincial and state requirements, including programs to reduce or offset air emissions. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures or additional operating expenses, or cause operations at certain facilities to end prior to the end of their useful economic lives. Failure to comply with such regulations could result in fines, penalties or the curtailment of operations.

Capital Power complies with regulatory requirements while working to reduce its environmental impact. The following outlines current environmental regulations and corporate initiatives that have or may have a significant impact on Capital Power's operations.

Climate-Related Financial Disclosure

Capital Power has prepared an assessment of climate-related risks and opportunities to conform with the recommendations of the Task Force on Climate-related Financial Disclosure (TCFD). This involved exploring the resulting risks and opportunities of three different scenarios, including scenarios with both favourable and unfavourable outcomes, and one of which was a scenario in which global temperatures are reduced to limit the global temperature increase to 2 degrees Celsius (or lower) above pre-industrial levels (a "two-degree scenario"). This document can be accessed via the Company's website at **https://www.capitalpower.com/CCD**.

Canadian Federal Government

Greenhouse Gas Regulation – Coal Generation

The GHG Regulations were published in the Canada Gazette, Part II on September 12, 2012. The GHG Regulations apply a performance standard of 420 kilograms of CO_2 emissions per gross output in MWh per year, which is intended to represent the intensity level of natural gas combined cycle technology. The performance standard applies to new coal-fired electricity generation units (defined as having a commissioning date of July 1, 2015 or later) and to older units that have reached the end of their useful life which is defined as:

- the earlier of 50 years from the date a generating unit commenced commercial production of electricity or the end of 2019, for existing generating units commissioned before 1975;
- the earlier of 50 years from the date a generating unit commenced commercial production of electricity or the end of 2029, for existing generating units commissioned from 1975 to 1985; and
- 50 years for existing generating units commissioned after 1985.

The GHG Regulations include provisions under which the end of life requirements can be avoided through a temporary exemption if, in the case of a new unit, it is designed to integrate CCS or, in the case of an existing unit, it can be retrofitted to integrate CCS. An application for such an exemption must include economic and technical feasibility studies and an implementation plan demonstrating that the unit will be in compliance with the GHG Regulations by January 1, 2025.

On October 27, 2017, ECCC recommended to the Minister amendments to the regulations for coal-fired generation and new regulations for new and converted gas-fired generation. On February 17, 2018, the federal government published the final amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (CST) in the Canada Gazette, Part II, Volume 152, No. 7. Under these amendments, coal units will be phased out on December 31, 2029, which will not align with Alberta's date for the phase out of coal units. However, if there is an equivalency agreement with the Province of Alberta, the federal deadline of December 31, 2029 could be extended.

Greenhouse Gas Regulation – Natural Gas Generation

On February 17, 2018, the Government of Canada published the final Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity in the Canada Gazette, Part II, Volume 152, No. 7. Under the final regulations, CTG units were granted 0, 5, 8 or 10 years of additional operational life beyond their coal-fired EoULs which were established under previously established regulations for coal-fired generation. The duration of additional operational life for CTG units is based on their environmental efficiency as measured in tonnes of carbon per MWh. Boilers that meet more stringent efficiency requirements are permitted to operate longer, up to 10 years post EoUL**.**

For gas turbines, large units will be subject to a 0.42 tonne of carbon dioxide equivalent per megawatt (CO3e/MWh) standard, while small units will be subject to a 0.550 t/MWh standard (gross basis). Small units are those that are rated equal to or less than 150 MW, large units are rated greater than 150 MW. The standards implemented by these regulations will not likely impact Clover Bar, Joffre, Shepard, Genesee 4 and 5 and Island Generation and other future Capital Power natural gas-fired generation projects.

Pan-Canadian GHG Framework

On October 23, 2018, the federal government announced additional details regarding the federal carbon pricing system under the Framework and published draft regulations amending the *Greenhouse Gas Pollution Pricing Act* (Canada), which received royal assent in June 2018. The amended *Greenhouse Gas Pollution Pricing Act* sets out a federal carbon pricing system based on a two-pronged approach: (1) a charge on fossil fuels that are consumed within a province or territory, which will be administered by the Canada Revenue Agency; and (2) an output-based pricing system that will apply to large industrial facilities, which will be administered by ECCC. The draft regulations, among other things, list the jurisdictions in which the federal fuel charge will apply and the rates at which it will apply.

Under the Framework, provinces and territories are enabled to design their own pricing systems that meet the federal standard. Under the draft regulations, the federal 'backstop' carbon price will start at $20 per tonne in 2019 and increase by $10 per tonne per year until reaching $50 per tonne in 2022. To minimize uncertainty, the federal price will remain in effect at least until 2022.

British Columbia, Alberta, Quebec, Nova Scotia, Prince Edward Island, Newfoundland and Labrador, and the Northwest Territories have all implemented or are on track to implement carbon pollution pricing systems that meet the federal benchmark and will not be subject to the federal carbon pricing system for 2019.

The federal output-based pricing system for large industry will apply starting in January 2019 in Ontario, Manitoba, New Brunswick, Prince Edward Island and Saskatchewan, either because those provinces have decided not to implement a carbon pricing system or they have implemented a system that does not meet the federal standard. The federal fuel charge will come into effect in those provinces on April 1, 2019. The federal pricing system will also apply in Yukon and Nunavut (jurisdictions that chose to opt-in to the federal system), where the fuel charge will come into effect in July 2019.

On August 30, 2018, the Government of Alberta announced that the province was pulling out of the Framework as a result of the Federal Court's decision to quash the approval of the Trans Mountain expansion project. While the Alberta Climate Leadership Plan remains in effect, in Alberta, the carbon price will not increase above $30 per tonne until the start of construction of the Trans Mountain expansion project. In addition, both Saskatchewan and Ontario have challenged the federal government's legal authority to impose a carbon price on the provinces and the legitimacy of the *Greenhouse Gas Pollution Pricing Act* (Canada). The Province of British Columbia has agreed to support the federal government by intervening in court actions in the Saskatchewan and Ontario Courts of Appeal.

On December 20, 2018, the Government of Canada released further details on the output-based pricing system, which will apply in January 2019. In addition, ECCC released a Policy Regarding Voluntary Participation in the federal output-based pricing system outlining considerations that will be taken into account when determining whether a facility can voluntarily participate in the output-based pricing system. The output-based pricing system for coal is 0.800 tCO_2e/MWh and will drop to 0.65 tCO_2e/MWh in 2020 and decline linearly after that to reach 0.37 tCO_2e/MWh in 2030. The output-based pricing system for natural gas is 0.37 tCO_2e/MWh. Co-fired or converted coal facilities would be measured against the coal benchmark.

Air Emission Regulations

On November 18, 2017, ECCC released its guidelines for the reduction of NO_x emissions from natural gas-fuelled stationary combustion turbines (guidelines), under section 54 of the *Canadian Environmental Protection Act, 1999*. The guidelines introduce a NO_x emission limit that is up to 50% more stringent than emission limits set out in the national emission guidelines for new natural gas–fuelled stationary combustion turbines published by the Canadian Council of Ministers of the Environment in 1992.

The guidelines provide baseline emission limits for NO_x from natural gas-fuelled stationary combustion turbines, however, the guidelines do not prevent provinces or territories from setting more stringent emission requirements for combustion turbines via their own provincial policies.

The guidelines adopted through this initiative would not impact existing operations of Clover Bar, Joffre, Shepard and Island Generation. Genesee 4 and 5 emissions are expected to be under the guideline limits and would be able to meet the guideline limits.

Regional Electricity Cooperation and Strategic Infrastructure Initiative

In *Budget 2016,* the Government of Canada announced funding for regional dialogues and studies to identify the most promising electricity infrastructure projects with the potential to achieve significant GHG reductions. Natural Resources Canada subsequently established the Regional Electricity Cooperation and Strategic Infrastructure Initiative, including project Steering and Technical Advisory Committees which include provincial representation. Alberta is represented on the Western Canadian committee by the AESO. Natural Resources Canada commissioned GE Energy Consulting to execute a technical study, with input and data provided by committee members representing four Western provinces (British Columbia, Alberta, Saskatchewan and Manitoba), and the Northwest Territories. The objective of the study was to evaluate the most promising electricity infrastructure projects in the Western provinces with the potential to transition to a sustainable non-emitting electricity generation portfolio. The study was completed in August 2018. Among the projects evaluated, the report found a new Manitoba-Saskatchewan intertie, restoration of the existing Alberta-BC intertie, and electrification of LNG and upstream natural gas production to be the most compelling GHG reduction opportunities from a cost-benefit perspective. The Company understands the issue of potential utility corridors and potential intertie expansion across Canada were discussed at the December 2018 Federal Ministers' meeting. The final statement from that meeting noted only that "interested jurisdictions could explore opportunities for utility corridors in Canada". At this time, it is the Company's understanding that Alberta is not currently interested in exploring such opportunities with adjacent jurisdictions. The Company will continue to monitor developments regarding this issue and engage with provincial and federal officials as appropriate.

Alberta

Climate Change Strategy

The Government of Alberta announced that the province is pulling out of the federal climate plan because of the federal court decision that resulted in halting development of the Trans Mountain Pipeline expansion. The Alberta Climate Leadership Plan remains in effect but the carbon price will not escalate beyond $30 until construction has resumed on the Trans Mountain Pipeline expansion.

In January 2016, the Government of Alberta directed the AESO to provide recommendations regarding the development and implementation of a plan to bring on new renewable electricity generation capacity to achieve up to 30% of Alberta's electricity generation from renewable sources by 2030 as envisioned by Alberta's Climate Leadership Plan. In November 2016, the Government of Alberta provided further clarification of its renewable energy targets, while the AESO provided information regarding the first competitive process it will undertake to procure new renewable energy under the program. The Government of Alberta confirmed that the REP will provide financial support for 5,000 MW of renewable electricity capacity by 2030 using a competitive process. The Government also introduced the Renewable Energy Act (Bill 27) in November 2016 to establish the legislative framework for the REP. It established that the target is for "at least" 30% of Alberta's electric energy generated by the end of 2030 to be from renewable sources. It also includes provisions that the Minister may establish interim targets and conduct periodic progress reviews, which are to be made public.

On December 13, 2017, the Government of Alberta announced the results of the first round of the REP process, namely the procurement of approximately 600 MW of renewable electricity capacity. RESAs were awarded for 20-year terms and will be supported using an "Indexed Renewable Energy Credit" mechanism, which is a contract for differences in which the contract will settle the difference between the winning bidders' bid prices and the pool price for electricity. The Company was selected as one of three successful proponents for Whitla 1. See "General Development of the Business – Company History – 2017 – Whitla Awarded 20-Year Contract by AESO in First Round of REP".

Greenhouse Gas Regulation

SGER came into force on August 1, 2007 and is applicable to all facilities in Alberta that produce more than 100,000 tonnes of GHG per year. For each eligible facility, SGER imposes a CO_2e intensity reduction from the average CO_2e emissions intensity based on the 2003 to 2005 period. The Government of Alberta recognizes three alternative mechanisms for compliance with this regulation:

(i) reduce actual emission intensity below the applicable net emissions intensity limit permitted by SGER, or purchase or use emission performance credits awarded to owners of facilities who reduce emission intensity below the regulated requirement;

(ii) payment into the Government of Alberta Climate Change Emission Management Fund for all emissions in excess of the emission intensity target; or

(iii) purchase of GHG emissions offsets created from Alberta based projects.

On June 25, 2015, the Government of Alberta announced changes to the SGER program whereby the CO_2e intensity reduction requirement under SGER would increase from 12% to 15% in 2016, and increase again to 20% in 2017. The Government of Alberta also announced that payments into the Climate Change Emission Management Fund would increase from $15 per tonne to $20 per tonne in 2016 and $30 per tonne in 2017.

On January 1, 2018, SGER was replaced with the Carbon Competitiveness Incentive Regulation (CCIR). Under the CCIR, power generation will be subject to a carbon tax of $30 per tonne of CO_2e emissions, for emissions that are greater than 0.37T CO_2e/MWh. If a facility's emissions exceed the prescribed benchmark, the resulting compliance obligation can be met through the use of Emission Performance Credits (EPCs) or offsets, or through payment to the Climate Change and Emissions Management Fund. The CCIR imposes limits on the use of EPCs and offsets within each compliance year, which begin at 50% and increase by 60% by 2020. CCIR also phases in legislated expiry periods for credit vintages starting in the 2020 compliance period until reaching a go-forward 8-year vintage expiry period in 2022.

Capital Power will retire the maximum allowable emissions offset credits to meet its 2018 CCIR compliance obligation and purchase Fund credits for the remainder. Therefore, the approximate total cost of compliance for Capital Power for the 2018 reporting period, split by Capital Power's generating assets for the 2018 reporting period (under CCIR), are as follows:

- Genesee 1 & 2 is expected to be approximately $2.8 million. This figure is net of the compliance obligation recoverable from the PPA buyer under the terms of the PPA.

- Genesee 3 is expected to be approximately $19.1 million (representing Capital Power's 50% interest).

- Genesee Mine has opted into the CCIR program and the cost for 2018 is expected to be approximately $0.07 million (representing Capital Power's share of the obligation).

- Keephills 3 is expected to be approximately $19.5 million (representing Capital Power's 50% interest, and including the compliance for the Highvale Mine coal used at Keephills 3).

- Clover Bar is expected to be approximately $2.6 million.

- Shepard Energy Center is expected to be approximately $0.15 million (representing Capital Power's 50% interest).

Under the operating approvals for Genesee 3 and Keephills 3, Capital Power was required to offset its emissions to the equivalent of a natural gas combined cycle plant. This requirement is now met through regulation under the current CCIR program. Capital Power also voluntarily offsets 100% of its scope 2 emissions at the Calgary and Edmonton offices by retiring offsets and RECs against those emissions.

Capital Power has been acquiring offsets for over a decade and has entered into more than 65 offset purchase agreements across North America. Capital Power invested approximately $21 million in Alberta Compliance offsets in 2018 (in line with 2017's investment of $21 million).

Air Emission Regulations

The federal and Alberta governments support CTG units to reduce GHG and air emissions, maintain grid reliability, and to help avoid stranded asset issues in the future, like those due to the early coal phase-out. Air emissions from the electricity sector in Alberta are managed by the 2003 CASA Framework, which does not include a recommendation regarding CTG units as the conversion was an unlikely scenario under the previous market structure. As such, the Government of Alberta formed a multi-stakeholder group under the CASA organization to develop and recommend draft NO_x standards for CTG units by December 31, 2017.

On February 20, 2018 the Government of Alberta adopted the CASA Board of Directors recommendations on the CTG Unit Conversion NO_x Emission Standard Agreement and issued the NO_x emission policy for CTG units (CTG NO_x Policy).

According to the CTG NO_x Policy, CTG subcritical units' NO_x emissions would be 50% of their 2003 CASA baseline emissions. Converted Genesee 1 & 2 units to natural gas must meet 1.06 kg/MWh (net basis). No NO_x emission reductions would be required for supercritical units until the federal end of life of the converted units. To demonstrate compliance with the NO_x emission standards, units would have an annual emission intensity test. Failure to comply with the annual emission intensity would be considered an environmental non-compliance.

The CASA 5-Year Electricity Framework Review began in July 2018. The review is undertaken by a multi-stakeholder committee comprised of representatives from the electricity industry, cogeneration operators, the Government of Alberta, and non-governmental organizations. The intent of the review is to evaluate the current regulatory framework for air pollutants, and seek consensus on recommendations to the Government of Alberta for appropriate actions to control emissions. The CASA 5-year review has reached non-consensus on NO_x standards for new gas-fired turbines. The non-consensus NO_x standards report was forwarded at the end of 2018 to Alberta Environment and Parks (AEP) for consideration.

BC

BC will increase its carbon tax to match the proposed federal carbon tax. BC will also expand the reach of its carbon tax to include several previously excluded emitting sources. As of April 1, 2018, BC's carbon tax will increase $5 per tonne from $30 per tonne to $35 per tonne, and will continue to increase in $5 per tonne increments annually until it reaches the federally imposed $50 per tonne price floor in 2021. Capital Power's operations in BC do not have any carbon tax exposure.

Ontario

On October 30, the Ontario Legislature passed Bill 4, Cap and Trade Cancellation Act, 2018, officially cancelling Ontario's Cap and Trade program. Bill 4 repeals the *Climate Change Mitigation and Low-carbon Economy Act, 2016* and sets out the legal framework for the wind-down of the greenhouse gas cap-and-trade program including the compensation framework. It also requires the Ontario government to "prepare and publish a climate change plan and to set targets for reducing the amount of greenhouse gas emissions in Ontario". In late November 2018, the Minister of the Environment, Conservation and Parks released "A Made-In-Ontario Environment Plan" (the Made-In-Ontario Plan) that provided an outline of the Province's plan to reduce GHG emissions. At this juncture, it is not clear whether Ontario will be subject to a Made-In-Ontario Plan or be subject to the federal carbon pricing system (the Framework). Ontario and Saskatchewan have commenced legal actions to challenge the Framework and the federal government's jurisdiction to impose a federal carbon price. Similar to when Ontario implemented its cap-and-trade program (and the PPAs for East Windsor and York were amended to compensate for GHG costs), the Company anticipates amendments will be made for the federal or provincial plan that prevails.

United States

Greenhouse Gas Regulation

The US EPA's Cross-State Air Pollution Rule (CSAPR) requires 28 eastern states to reduce SO_2 and NO_x emissions from power plants to enable downwind states to meet federal air quality standards. Risk to the Company's operating assets is minimal given North Carolina's removal from the ozone program in 2016, which has led to decreased compliance costs for Southport and Roxboro. The North Carolina plants and Decatur will continue to purchase allowances for annual SO_2 and NO_x emissions, which totaled less than $18,000 for 2017. Modifications to the CSAPR program are not expected at this time.

On August 21, 2018, the US EPA released a proposal to replace the Clean Power Plan (CPP) with the Affordable Clean Energy Rule (ACE). Under ACE, states would be required to conduct a unit specific evaluation of the potential for heat rate improvements at existing fossil fuel plants, which then would be used to establish emission standards for units within their state. States would have discretion to consider additional factors such as remaining useful life, even if consideration of these factors would result in the application of the performance standard in a less stringent manner than would otherwise be required. ACE is not expected to negatively impact any of Capital Power's operating assets in the United States as they are not affected sources under ACE as currently proposed.

Regional Greenhouse Gas Initiative (RGGI)

The RGGI is a regional cap-and-trade program to reduce CO_2 emissions from power plants in nine northeastern states. The original Memorandum of Understanding among the participating states established a programmatic review every four years, including evaluating of the cap level.

On December 19, 2017, RGGI released a Final Model Rule to extend the program through 2030. The model rule includes a lower cap starting in 2021, an annual decline in the regional cap through 2030, resulting in a 30 percent reduction from the 2020 cap), full bank adjustment for pre-2021 vintage allowances, emissions containment reserve and trigger price, and the elimination of certain offset categories. The cost containment reserve will continue to make allowances available when prices are high. The emissions containment reserve will divert allowances from the auction if prices are low. States are beginning to follow state-specific processes to update their own CO_2 trading programs with the intent to ensure that their component of the regional program changes are effective as soon as possible, and by no later than January 1, 2021.

In May 2018, the New Jersey Board of Public Utilities announced that it was initiating an economic analysis to evaluate the cost and benefits of rejoining RGGI (they withdrew in 2011). In September 2018, the Virginia Department of Environmental Quality released a revised proposed regulation to link with RGGI.

Capital Power will continue to trade Regional Greenhouse Gas Initiative allowances as an environmental commodity.

Health, Safety and Environment

Health, Safety and Environment Policy

If not properly managed, Capital Power's activities with respect to the construction, operation, and maintenance of power generation and related facilities can present significant risks to human health, safety, and the environment. To mitigate these risks, Capital Power's Board approved HSE Policy defines a framework under which the organization's HSE program is developed and maintained. The HSE Policy enables Capital Power to minimize the impacts of occupational injury and illness and negative impacts to the environment, by ensuring:

- compliance with all applicable laws and regulatory requirements;
- proactive administration and management of health, safety and environment-related risks within Capital Power's operations, maintenance and construction activities;
- continuous review and improvement of the HSE Policy and the related policy framework;
- appropriate goals and monitoring of performance in respect of those goals;
- alignment of contractors with the HSE Policy; and
- promotion of a zero-injury culture, healthy lifestyles, and environmental responsibility to foster and support excellence in Capital Power's HSE performance.

Every employee and contractor of Capital Power is responsible for Capital Power's HSE performance, and the health and safety of themselves and their fellow employees.

Capital Power manages its HSE risks through a company-wide HSE management program and measures its HSE performance against recognized industry and internal performance measures. Compliance audits are conducted by internal and external auditors to verify that the HSE management program meets the regulatory requirements for the business.

Board approved HSE performance indicators are established annually to promote Capital Power's HSE stewardship.

Health, Safety and Environment Initiatives

To manage HSE risks and promote a zero-injury and environmentally responsible culture, Capital Power engages in the following activities:

- Conducts regular HSE audits of its operations and construction activities, tracking items of non-compliance and reporting on progress to the HSE Committee of the Board.
- Requires, and encourages the reporting of hazards and near miss events. These events are tracked and analysed for trends, and preventative actions are taken because of those trends.
- Delivers ongoing HSE training to all employees of Capital Power. Training is required for all employees in field or operating positions and the completion of such training is tracked and monitored by Capital Power.
- Regularly reviews HSE regulatory updates to ensure awareness of upcoming regulatory changes.

Specific environmental initiatives include the following activities:

- Capital Power entered into an agreement with the Province of Alberta to eliminate all emissions from coal at the Company's Alberta generation facilities by the end of 2030. See "Material Contracts – Off Coal Agreement".
- Capital Power launched the Genesee Performance Strategy, committing up to $50 million in capital investment to the initiative to reduce carbon emissions at the Genesee facilities by 10% or more by 2022.
- Capital Power is currently participating in Alberta's REP through the Whitla wind project and continues to develop a pipeline of projects that could be bid into future REP rounds, which are expected to procure 5,000 MW of new renewables between 2016 and 2030.

- Shepard was announced as the test site for the natural gas track of the prestigious $20 million NRG COSIA Carbon XPRIZE, a global competition to develop breakthrough technologies that convert carbon dioxide into valuable products.

- Capital Power and the Pembina Institute conducted an innovative *Wind Energy in Alberta: Sustainable Communities, Sustainable Environment* multi-stakeholder workshop. The workshop explored how the anticipated investment in wind energy in Alberta (5,000 MW of new renewable power generation expected by 2030) can be accomplished while bringing long-term, sustainable benefits for Alberta communities. The workshop involved over 100 participants including municipal councillors, provincial government staff, conservation groups, landowners, environmental and health consultants, land agents, and developers.

- Capital Power continues to serve on the board of the West Central Airshed Society. This society monitors and promotes effective management of air quality within the air shed zone. The zone is approximately 46 thousand square kilometres and spans from the western boundary of the Edmonton city limits to the BC border.

- Capital Power co-chairs the AISC. The AISC is a committee of the Canadian Electricity Association, Generation Council and is comprised of Generation Council company representatives. The committee serves to monitor, engage with, and respond to federal government initiatives and policies regarding climate change and air quality issues. The AISC worked closely with the Government of Canada on the reduction of CO_2 emissions from coal-fired generation of electricity regulations, the Canadian Ambient Air Quality Standards, and the Base Level Industrial Emissions Requirements.

- Capital Power continues to engage in land reclamation activities to reclaim land no longer needed with respect to the mining operations of the Genesee coal mine. To date, the reclamation work at Genesee coal mine has returned about 1,142 hectares (37% of the total surface area at the Genesee coal mine) of previously mined area into productive farm land and wildlife habitat.

- A long-term regional biomonitoring program encompassing the Genesee facilities is one of the largest programs of its kind in Canada. Since 2004, its air, water and wildlife studies have found no significant changes in land, natural water bodies or ambient air quality.

- The use of biomass and tire-derived fuel has increased since 2013. Capital Power's Roxboro and Southport facilities optimized their fuel mix for increased consumption of biomass and tire-derived fuel and decreased their consumption of coal.

- Capital Power is actively increasing natural gas co-firing at Genesee to support emissions reductions.

- Capital Power minimizes the amount of coal by-product going to the landfill by selling it for use in cement production.

Specific health and safety initiatives include the following activities:

- Implementation of the Maximo Incident Management module which fully integrates incident reporting and management (including investigations) into plant work management processes. The implementation includes a robust reporting framework to assist in enhanced incident reporting and analytics capabilities.

- An update to Capital Power's programs and standards to align with changes made to Alberta's *Occupational Health and Safety Act*.

- In 2018, Roxboro received a North Carolina Department of Labor Safety award for an outstanding safety record for 2017 operations. The awards are presented to companies that have above-average worker health and safety programs.

- In 2018, Capital Power was awarded the Canadian Electricity Association President's Award of Excellence for Employee Safety for 2017 safety performance concerning the Company's Canadian operations. This is the fifth consecutive year that Capital Power's safety performance received recognition from the Canadian Electricity Association.

- Ten Life Safety Critical Rules were set and communicated throughout the Company. The Life Safety Critical Rules are intended to prevent actions which have the potential to result in a fatality or serious injury, and help Capital Power achieve its goal of zero injury. From 2016 through 2018, Life Safety Critical Standards were developed and implemented throughout the organization. In 2018, Life Standard development was completed with the release of the Driving Standard and revisions to the Alcohol and Drug Standard.

- Formal Hazard Assessments were reviewed and standardized across the organization in 2016; a preventative and consistent approach to identify and control hazards in the workplace. In 2017, a revised Hazard Identification, Assessment and Control Standard was released.

- HSE leadership training which provides people leaders with a fundamental base of knowledge required in the development and implementation of an HSE management program. In 2018, leadership training was provided on the revisions to the Alcohol and Drug Standard.

- A Significant Incident Investigation Committee which serves to ensure incident investigations and root cause analysis are completed in a timely manner, completed at a level appropriate for the incident, action plans are identified, and learnings are shared across the organization.

- All of Capital Power's offices, operating facilities and construction sites have health and safety committees which management and workers as members and which align to jurisdictional requirements.

- An update to corporate, operations/construction and site-specific orientations with an additional requirement for Senior Site Leadership participation in site-specific orientations for their contractors.

- Construction and operations crews hold daily safety meetings to review hazards of their tasks and identify additional control measures which may be required.

- HSE Improvement Plans were implemented at all facilities and for the Construction and Engineering Group.

- Capital Power has formalized its Contractor HSE Management Process to include all four phases of construction and provides the opportunity to manage contractor performance from pre-qualification (supported by ISNetworld) right through to job completion. To ensure the standard was imbedded into site work practices, HSE completed compliance audits during 2018 across all operated facilities.

- A workplace inspections program is in place which includes office, facility, and construction inspections. The program also includes Executive Team inspections, focused contractor inspections and contractor inspections during outages.

- A Work Readiness-Warmup and Stretching Program was piloted at the Southport facility. The program has been developed to help prevent musculoskeletal disorders (MSDs).

Personnel

As at December 31, 2018, the total number of persons employed by Capital Power is 813. As at December 31, 2018, approximately 641 full-time, part-time, temporary, and casual employees work in Capital Power's Canadian operations and 172 are employed in Capital Power's US operations.

There are three Canadian labour unions, in four bargaining units, which together represent approximately 38% of Capital Power's Canadian labour force and approximately 30% of Capital Power's overall work force. The bargaining units are:

- the Civic Service Union 52, which represents administrative, technical, professional and information technology employees located in the Edmonton corporate office and Genesee power plant;
- the International Brotherhood of Electrical Workers Local 1007, which represents electrical, instrument and mechanical tradesmen, coal plant operators, equipment and crane operators, utility workers, tool servicemen and related employees at the Genesee power plant;
- the UNIFOR Local 829, which represents power engineers at the Genesee power plant; and
- the UNIFOR Local 1123, which represents shift engineers, electrical and instrumentation technicians and mechanical maintenance technicians at Island Generation.

Currently, Capital Power is bargaining with UNIFOR 829, setting dates with IBEW 1007 to commence bargaining, and have not started the bargaining process with CSU 52. The following table provides a summary of the status of Capital Power's collective agreements in force. For clarity, Capital Power's collective agreements remain in force until they are replaced with new collective agreements reached through the bargaining process.

Bargaining Unit	Location	Effective Date	Expiry date
CSU 52	Edmonton, AB	November 17, 2015	December 23, 2018
IBEW Local 1007	Edmonton, AB	September 22, 2016	December 22, 2018
UNIFOR Local 829	Edmonton, AB	December 25, 2016	December 25, 2018
UNIFOR Local 1123	Campbell River, BC	May 1, 2015	April 30, 2021

REGULATORY OVERVIEW

The following is an overview of the principal electrical power regulatory regimes to which Capital Power's current operations are subject. Environmental regulations affecting Capital Power's operations are discussed under "Business of Capital Power – Environmental Regulation".

Alberta

Since January 1, 1996, new generation capacity initiatives in Alberta have been undertaken by IPPs and are subject to market forces, rather than rate regulation. Regulated generating units, including those owned and operated by Capital Power, became subject to PPAs that were auctioned by the Government of Alberta to buyers in 2000. The Balancing Pool assumed the responsibilities of "PPA Buyer" for those generating units that were subject to a PPA not acquired in the initial 2000 auction, including Genesee 1 & 2. Power from PPA generating units and merchant generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by AESO, based on offers by generators to sell power. The MSA is an independent entity responsible for monitoring the behaviour of market participants, including AESO and the Balancing Pool, investigating behaviour that may not be consistent with the fair, efficient and openly competitive operation of the market and enforcing compliance with all applicable legislation, regulations, and AESO and AUC rules. The AUC oversees electricity industry matters including approvals for construction and operation of new power plant and transmission facilities, and regulated rates for transmission, distribution and sale of electricity and natural gas to end-use consumers. The AUC is also responsible for approving AESO rules, for considering complaints and objections filed in respect of AESO rules, and for determining penalties and sanctions on any participant found to have contravened market rules.

The *Responsible Energy Development Act* created a single regulator, the AER, which became operational in June 2013. The AER is responsible for all oil, gas, oil sands and coal mining projects in Alberta, combining certain responsibilities previously assigned to the ERCB and Alberta Environment. The AER oversees energy development projects from the application through the reclamation phases of project development. Capital Power's coal mining related activities are subject to oversight by the AER.

On November 22, 2015, the Government of Alberta announced its Climate Leadership Plan discussed above. For updates see "Business of Capital Power – Environmental Regulation – Alberta – Climate Change Strategy" for details on the measures announced in the Climate Leadership Plan that will directly impact the electricity sector in Alberta.

Alberta Announcement of Transition to a Capacity Market

On November 23, 2016, the Government of Alberta announced that it will transition Alberta's market design from an energy-only market to a capacity market. The decision followed a review undertaken by the AESO in 2016 that resulted in the AESO's assessment that the existing energy-only market would not ensure system reliability and supply adequacy while also achieving the Government of Alberta's environmental objectives as set out in the Climate Leadership Plan.

The capacity market is to be operational by the fourth quarter of 2021. The AESO has been directed by the Government of Alberta to develop the technical design and details for the capacity market, which, among other things relate to how the energy, ancillary services and capacity markets will collectively function, how much capacity will be procured, over which time periods and for what duration as well as eligibility and delivery obligations for participants. In these respects, the AESO and the Government of Alberta have indicated that the design of Alberta's capacity market will be informed by the experiences of US and other markets that currently have capacity markets, but tailored to take into account unique features of Alberta's electricity system.

The AESO has completed stakeholder consultations and is finalizing draft rules. Those rules are expected to be filed with the AUC in early 2019 for approval. The first capacity auction is expected to commence in late 2019 for delivery in Q4 of 2021.

The transition to a capacity market stands to impact Capital Power's existing facilities and future development opportunities by changing the market mechanisms through which existing and new capacity compete, recover fixed and variable costs and earn a return on and of invested capital. Capital Power has been and will continue to actively participate in the development of the new capacity market, to mitigate transition risks for the Company's assets and ensure the Company's continued competitiveness and sustainability in the capacity market. In these respects, the Company notes the commitments made by the Government of Alberta as part of its November 23, 2016 announcement that existing investments will be treated fairly in the transition, and that a level playing field for existing and new investments to compete to provide capacity in the new market will be maintained.

In parallel with the development of a capacity market, the Government of Alberta will also be developing policy frameworks to address issues relating to coal-to-gas conversions, hydro development, and the existing transmission policy. Capital Power will participate in those processes as well, given potential implications for the Company's existing operations, future development opportunities, and the broader design and operation of the capacity market.

Transmission Issues

Under amendments to the EUA introduced in 2009 as Bill 50, the Government of Alberta was empowered to designate certain transmission projects as critical infrastructure, and to approve the need for such facilities. Bill 50 identified and described five projects deemed as CTI projects, including two North-South transmission reinforcement projects that would increase transmission capacity between the Edmonton and Calgary regions. These two projects are known as the West Alberta Transmission Line and the East Alberta Transmission Line. The AUC remains responsible for reviewing and approving other aspects of CTI projects.

Amendments to the EUA enacted in December 2012 repealed Bill 50, but grandfathered the existing CTI projects. The West Alberta Transmission Line and the East Alberta Transmission Line were both commissioned in December 2015. The existing CTI projects will increase the capacity and reliability of the transmission system and address transmission congestion that could arise between the areas of Alberta where Capital Power's generating stations are located and the loads drawing on the system.

The Alberta Government has also implemented changes to enhance the scrutiny by the AUC of the costs associated with new power lines. Amendments to the Transmission Regulation, and a Transmission Deficiency Regulation, which include provisions for approved cost estimate, a cost oversight management function and improved cost reporting, were approved in September 2014. Both the CTI projects referred to above and additional transmission work required to carry electricity within Alberta are costly. The increased scrutiny of these costs should ensure that the costs associated with transmission facilities are reasonable in the circumstances. If the costs are too high, some customers may choose to leave the system by producing their own electricity on-site.

As noted, the Government of Alberta has advised of its intentions to undertake a review of the transmission policy framework as part of the transition to a capacity market. The scope and timelines for the review are currently unknown. The impact to Capital Power of any changes potentially arising from the review are currently unknown and will depend on, among other things, the nature of the changes themselves and on how the details of the transmission framework are integrated and reflected in the design of the capacity market.

Transmission Line Losses

In Alberta, the costs associated with transmission losses on the Alberta Interconnected Electric System are charged to generators in accordance with a methodology established by the AESO. The AESO's line loss methodology was implemented in January 2006 and updated in January 2008. Under the line loss methodology, the AESO calculates location-specific loss factors for generators or groups of generators that can be charges or credits, and that must fall within a range prescribed by the Transmission Regulation. All of Capital Power's generating facilities are assigned loss factors pursuant to the line loss methodology.

The AESO line loss methodology for the 2006-2008 period was challenged by a third-party before the AUC and was found not to comply with the requirements of the Transmission Regulation. In a decision issued in January 2015, the Commission ruled that the post 2008-line loss rule also did not comply, and that it has the authority to order a remedy or relief to correct for the payment or receipt of line loss charges included in the AESO tariff from January 1, 2006 to the date a new rule goes into effect.

A proceeding was held in 2017 to establish the methodology to be used in determining retroactive line loss adjustments. The AUC issued a decision in December 2017 regarding the loss factor methodology to be used for determining retroactive adjustments back to January 2006. Implementation activities by the AESO have been held over the course of 2018 with plans to continue well into 2019.

The process to consider outstanding appeal applications filed by Capital Power and other parties commenced in mid-2018. The Alberta Court of Appeal held an oral hearing to consider whether to proceed with the appeal applications and on December 20, 2018 issued a decision rejecting some of the applications with a ruling on others expected sometime in 2019. The applications seeking to overturn the AUC's finding on jurisdiction to issue retroactive tariff adjustments were rejected. However, the Court of Appeal has yet to issue a decision on the applications challenging, among other things, the aspect of the AUC's 2017 decision establishing recipients of adjustment invoices. When this decision will be issued remains unknown but upon release, the process for this appeal is expected to be further clarified.

Estimates of Capital Power's potential exposure to retroactive charges are preliminary and subject to change based on the outcome of these processes. Capital Power will continue to pursue legal and regulatory measures to mitigate any potential exposure. See "Legal Proceeding and Regulatory Actions – Milner Power Inc. (Milner) Loss Factor Complaint" and "Risk Factors".

Transmission Constraint Management

As described above, power in Alberta is dispatched in accordance with an economic merit order administered by the AESO, based upon offers by generators to sell power. Where real-time transmission constraints preclude the offer that would otherwise have been dispatched, the AESO's TCM Rule is applied to dispatch the next available offer that is unaffected by the constraint, which then sets the price.

In April 2015, the AUC approved a new TCM Rule that it had directed the AESO to develop to address concerns with the previous rule. The new TCM Rule took effect in November 2015. Since that time, the AESO's reporting has indicated that the frequency of congestion, and related costs under the new TCM rule, have been negligible. The new TCM Rule has not had any material or adverse implications to date for the dispatch of Capital Power's facilities.

BC

BC's electricity is produced and delivered primarily by BC Hydro, a Crown corporation that is regulated by the BCUC. With significant interconnection to adjoining Western Electricity Coordinating Council markets, BC exports electricity through BC Hydro's trading arm and wholly owned subsidiary, Powerex Corporation.

Since 2003, the BC Government has taken steps to diversify the market and to promote new generation by IPPs. Under the direction of the BC Government, BC Hydro acquires electricity supply on a competitive basis from IPPs. Procurement of energy from IPPs is generally completed through calls for power, open offers and bilateral arrangements.

Capital Power has ownership interests in four facilities in BC. Island Generation is a combined cycle facility located near Campbell River which provides reliability services to Vancouver Island under a long-term tolling agreement with BC Hydro. Quality was commissioned in 2012 and provides renewable energy to BC Hydro under a long-term Electricity Purchase Agreement. The Savona and 150 Mile House waste heat facilities both produce zero-emissions energy and operate along Enbridge's Westcoast Energy BC Gas Pipeline. Both waste-heat facilities provide power to BC Hydro under long-term Electricity Supply Agreements.

Because of BC Hydro's market control in generation, distribution and trading, future opportunities for IPPs in BC may be limited.

British Columbia Climate Change Plan and Site C Clean Energy Project

In December 2018, the BC Government released its CleanBC plan, detailing BC's renewed efforts to combat climate change. Within the plan, specific measures to lower emissions were identified across major sectors of the economy in British Columbia. As a major tenet of the plan, the BC Government focused on efforts to use the abundant supply of electricity to increase electrification as a means of lowering emissions.

As a significant new source of hydroelectricity, the Site C dam on the Peace River will provide an additional 1,100 MW of capacity to support BC's efforts to increase electrification. After announcing the project would proceed in December 2014, it has now advanced to construction. Following an inquiry by the BCUC in November 2017, completed as directed by the Government of BC, it was established that the construction of the project would proceed as planned. When completed in 2024, the project will be a significant new source of electricity supply in BC.

Ontario

Ontario has a centrally planned electricity market, and with policy direction from previous governments, has significantly increased the amount of clean energy in Ontario's electric system. The Ontario Ministry of Energy takes a lead role in defining the electricity mix to be procured by the IESO, which has the mandate to develop a detailed power supply plan, to procure electricity, and to manage contracts for privately-owned generation. The IESO is responsible for managing the Ontario wholesale market and for ensuring reliability of the electric system in Ontario. Hydro One operates approximately 97% of Ontario's transmission network. The electricity sector is regulated by the Ontario Energy Board.

Capital Power has ownership interests in two thermal gas plants and two wind projects in Ontario. The York Energy Centre was commissioned in 2012 and is the largest quick-response gas-fired plant in Ontario, operating under contract with the IESO. East Windsor began commercial operations in 2009 and operates under contract with the IESO, with an additional long-term steam agreement for FMCC's Company's Windsor operations.

Capital Power's two wind projects are located in Southern Ontario. Kingsbridge 1 was developed pursuant to Ontario's Renewable Energy Supply program, which allowed for long-term PPAs for wind facilities. PDN began commercial operations in November 2013. The PDN facility was awarded a PPA pursuant to a FIT program. The FIT program, originating from the 2009 Ontario *Green Energy Act*, provides standard program rules, standard contracts and standard pricing for classes of renewable energy.

IESO Market Renewal

The Ontario IESO is in the preliminary stages of a Market Renewal Program (MRP), which is a series of coordinated initiatives expected to result in a fundamental redesign of Ontario's electricity market. The IESO's stated goal for the MRP is to improve how electricity is priced, scheduled and procured to meet Ontario's electricity system needs. The Company is actively participating in the MRP stakeholder process and collaborating with the IESO. The PPAs for the York Energy, East Windsor, Port Dover and Nanticoke and Kingsbridge 1 facilities contain provisions for renegotiation should there be a change in market rules. The intent of these provisions is to preserve the underlying supplier economics within the respective PPAs. Accordingly, the Company does not believe that implementation of the MRP will have a material adverse effect on its financial condition and results of operations.

United States

Capital Power's operations are subject to extensive regulation by US governmental agencies. Capital Power's projects are subject to US federal laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, and access to transmission. Generation facilities are also subject to US federal, state and local laws and regulations that govern, among other things, the geographical location, zoning, land use and operation of a project.

US Energy Industry Regulatory Matters

FERC Jurisdiction

Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of electric energy in interstate commerce is a public utility subject to FERC's jurisdiction. FERC has extensive ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy under the FPA and with respect to certain interstate sales, transportation and storage of natural gas under the *US Natural Gas Act* of 1938, as amended, and the US *Natural Gas Policy Act* of 1978, as amended. FERC also maintains certain reporting requirements for public utilities and regulates, among other things, the disposition and acquisition of certain assets and securities, the holding of certain interlocking directorate positions, and the issuance of securities by public utilities.

FERC mandates open access for transmission service in the US. A series of orders issued by FERC since 1996 have: i) unbundled utilities' transmission and generation services; ii) required those utilities to offer eligible entities open access to utility transmission facilities on a basis comparable to the utilities' own use of the facilities; and iii) set out standards for RTOs. RTOs are voluntary organizations operated by ISOs independent of market participants. RTOs perform planning, operations, and transmission services on a regional instead of utility specific basis. ISOs/RTOs serve two thirds of the wholesale power markets in the US. The six FERC-approved RTOs in the United States include: ISO-NE, New York ISO, PJM Interconnection, the Midwest ISO, the Southwest Power Pool and the California ISO. In addition, FERC approval is required for wholesale sales of power at market based or cost-based rates. This approval is granted if FERC finds that the seller and its affiliates: lack market power in generation and transmission; cannot erect other barriers to market entry; and comply with certain affiliate restrictions. This authorization is subject to revocation by FERC if such companies fail to continue to satisfy FERC's current or future criteria for market based rate authority or to modification if FERC restricts the ability of wholesale sellers of power to make sales at market based rates. All of Capital Power's power marketer affiliates are currently authorized by FERC to make wholesale sales of power at market-based rates.

Independent System Operators

FERC has the authority to enforce the statutes it is responsible for implementing and the regulations it issues under those statutes. It is empowered to impose civil penalties of up to US $1 million per day per violation for violations of the US Natural Gas Act of 1938, US Natural Gas Policy Act of 1978 and Part II of the FPA, with the potential of criminal fines and imprisonment for violations. FERC is also responsible for certification of power plant facilities operating in the wholesale markets. The North American Electric Reliability Corporation establishes and enforces reliability standards applicable to all owners, operators and users of the bulk power system. These standards are reviewed by FERC and thus are subject to FERC's enforcement authority.

North Carolina

Most of North Carolina is not part of an RTO or ISO. Thus, in most areas of the state, all transactions are bilateral and must be scheduled through the incumbent utility. Capital Power has three facilities in North Carolina, Southport, Roxboro and Beaufort, which are all in the non-RTO part of North Carolina. All three plants are QFs under the US Public Utilities Regulatory Policies Act of 1978 that incentivizes energy efficiency through use of cogeneration and renewable energy. They are contracted with Duke Energy Progress, LLC.

New Mexico

Most of New Mexico is not part of an RTO or ISO. Thus, in most areas of the state, all transactions are bilateral and must be scheduled through the incumbent utility. Capital Power owns one facility in New Mexico, Macho Springs, which is a 50 MW wind-powered facility located in Luna County, New Mexico. Macho Springs is located in the El Paso Electric Company balancing authority area; the non-RTO part of the state. Macho Springs is interconnected with transmission facilities owned by El Paso Electric Company, and all of the output is sold to Tucson Electric Power pursuant to a long-term PPA. Macho Springs is an exempt wholesale generator that is authorized to sell energy, capacity, and ancillary services at market-based rates.

Alabama

Capital Power owns Decatur, a 795 MW natural gas fired facility located in Decatur, Alabama. The state is not part of an RTO or ISO. Decatur operates in the Southeast Electric Reliability Council region. Energy and capacity markets in the area are bilateral, where vertically integrated utilities supply their own load, or purchase power from third parties under contracts. Decatur is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Decatur sells capacity to a regional entity under a contract which has an original term of 10 years and expires December 31, 2022.

Kansas

Capital Power owns Bloom, a 178 MW wind-powered facility located in Clark and Ford County, Kansas. The state is part of the Southwest Power Pool, which is an RTO that oversees the bulk electric grid and wholesale power market in the Central U.S. on behalf of a large group of utilities and transmission companies in 14 states. Southwest Power Pool formally became an RTO in 2004 and implemented its integrated marketplace in 2014, which includes a day-ahead energy market, a real-time energy market, and an operating reserve market. Bloom is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Bloom sells 100% of its output under a fixed-price contract with Allianz Risk Transfer into 2027.

Arizona

Capital Power owns Arlington Valley, a 580 MW gas-fired combined-cycle generation facility located in Arlington, Arizona. The state is not part of an RTO or ISO. Thus, in most areas of the state, all transactions are bilateral and must be scheduled through the incumbent utility. Arlington Valley is a FERC approved exempt wholesale generator that is authorized to sell power at market-based rates.

Arlington Valley sells capacity and electricity to Arizona Public Service under tolling agreements through 2025.

North Dakota

Capital Power owns New Frontier Wind, a 99 MW generation facility located in McHenry County, North Dakota. The state is part of MISO, an RTO that operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South – extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. New Frontier is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

New Frontier will swap the market revenue from a fixed volume of 87% of its generation for a fixed price payment over a 12-year term with an investment grade US financial institution.

RISK FACTORS

A discussion of the risk factors relating to Capital Power and its business and operations can be found in the section entitled "Risks and Risk Management" in the Company's MD&A for the year ended December 31, 2018 which section is incorporated herein by reference and is available on SEDAR.

COMMON AND PREFERRED DIVIDENDS

Common Dividends

For the three most recently completed financial years, the Company has declared the following: (i) on July 27, 2018, the Company announced a 7.2% dividend increase for its Common Shares effective for the third quarter 2018 dividend for an annualized dividend of $1.79 per Common Share, (ii) on July 26, 2017, the Company announced a 7.1% dividend increase for its Common Shares effective for the third quarter 2017 dividend for an annualized dividend of $1.67 per Common Share, (iii) on July 22, 2016, the Company announced a 6.8% dividend increase for its Common Shares effective for the third quarter 2016 dividend for an annualized dividend of $1.56 per Common Share, (iv) on July 27, 2015, the Company announced a 7.4% dividend increase for its Common Shares effective for the third quarter 2015 dividend for an annualized dividend of $1.46 per Common Share.

The payment of dividends is not guaranteed, however, and the amount and timing of any future dividends will be at the discretion of the Board after taking into account such factors as the Company's financial condition, results of operations, distributions from CPLP, current and anticipated cash needs, the requirements of any future financing agreements and other factors that the Board may deem relevant.

The following dividends have been declared on the Common Shares for the three most recently completed financial years

Dividends Declared	
Declaration Date	**Dividend per Share**
18 Feb 16	$0.365
22 Apr 16	$0.365
25 Jul 16	$0.390
17 Nov 16	$0.390
17 Feb 17	$0.390
28 Apr 17	$0.390
26 Jul 17	$0.4175
16 Nov 17	$0.4175
15 Feb 18	$0.4175
27 Apr 18	$0.4175
30 Jul 18	$0.4475
26 Oct 18	$0.4475
15 Feb 19	$0.4475

Preferred Dividends

From issuance, the Series 1 Shares paid fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2015.

On December 31, 2015, the annual fixed dividend rate on the Series 1 Shares was reset pursuant to their terms to 3.06% for the next five-year period ending December 31, 2020. The fixed cumulative dividends will be $0.765 per share per annum during this five-year period.

The following dividends have been declared on the Series 1 Shares for the three most recent completed financial years:

Dividends Declared	
Declaration Date	**Dividend per Share**
18 Feb 16	$0.19125
22 Apr 16	$0.19125
25 Jul 16	$0.19125
17 Nov 16	$0.19125
17 Feb 17	$0.19125
28 Apr 17	$0.19125
26 Jul 17	$0.19125
16 Nov 17	$0.19125
15 Feb 18	$0.19125
27 Apr 18	$0.19125
30 Jul 18	$0.19125
26 Oct 18	$0.19125
15 Feb 19	$0.19125

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The Series 3 Shares pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2018.

On December 31, 2018, the annual fixed dividend rate on the Series 3 Shares was reset pursuant to their terms to 5.453% for the next five-year period ending December 31, 2023. The fixed cumulative dividends will be $1.36325 per share per annum during this five-year period.

The following dividends have been declared on the Series 3 Shares for the three most recent completed financial years:

Dividends Declared	
Declaration Date	**Dividend per Share**
18 Feb 16	$0.2875
22 Apr 16	$0.2875
25 Jul 16	$0.2875
17 Nov 16	$0.2875
17 Feb 17	$0.2875
28 Apr 17	$0.2875
26 Jul 17	$0.2875
16 Nov 17	$0.2875
15 Feb 18	$0.2875
27 Apr 18	$0.2875
30 Jul 18	$0.2875
26 Oct 18	$0.2875
15 Feb 19	$0.3408125

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The Series 5 Shares pay fixed cumulative dividends of $1.125 per share per annum, yielding 4.50% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending June 30, 2018.

On June 30, 2018, the annual fixed dividend rate on the Series 5 Shares was reset pursuant to their terms to 5.238% for the next five-year period ending December 31, 2023. The fixed cumulative dividends will be $1.3095 per share per annum during this five-year period.

The following dividends have been declared on the Series 5 Shares for the three most recent completed financial years:

Dividends Declared	
Declaration Date	**Dividend per Share**
18 Feb 16	$0.28125
22 Apr 16	$0.28125
25 Jul 16	$0.28125
17 Nov 16	$0.28125
17 Feb 17	$0.28125
28 Apr 17	$0.28125
26 Jul 17	$0.28125
16 Nov 17	$0.28125
15 Feb 18	$0.28125
27 Apr 18	$0.28125
30 Jul 18	$0.327375
26 Oct 18	$0.327375
15 Feb 19	$0.327375

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The Series 7 Shares pay fixed cumulative dividends of $1.50 per share per annum, yielding 6.00% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2021.

The following dividends have been declared on the Series 7 Shares since the date of issuance of such shares:

17 Nov 16	$0.3616(1)
17 Feb 17	$0.375
28 Apr 17	$0.375
26 Jul 17	$0.375
16 Nov 17	$0.375
15 Feb 18	$0.375
27 Apr 18	$0.375
30 Jul 18	$0.375
26 Oct 18	$0.375
15 Feb 19	$0.375

Note:

(1) Initial quarterly dividend represents the period from October 4, 2016 (the date of issuance of the Series 7 Shares) to December 31, 2016.

The Series 9 Shares pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending September 30, 2022.

The following dividends have been declared on the Series 9 Shares since the date of issuance of such shares:

23 Aug 17	$0.2048(1)
16 Nov 17	$0.359375
15 Feb 18	$0.359375
27 Apr 18	$0.359375
30 Jul 18	$0.359375
26 Oct 18	$0.359375
15 Feb 19	$0.359375

Note:

(1) Initial quarterly dividend represents the period from August 9, 2017 (the date of issuance of the Series 9 Shares) to September 30, 2017.

Dividend Reinvestment Plan

On January 1, 2012, the Company launched a DRIP. Eligible shareholders were able to elect to participate in the DRIP commencing with the Company's first quarter 2012 cash dividend on its Common Shares. The DRIP provides eligible shareholders with an alternative to receiving their quarterly cash dividends on Common Shares. Under the DRIP, eligible shareholders that so elect accumulate additional Common Shares by reinvesting their quarterly cash dividends on the applicable dividend payment date in new Common Shares issued from treasury. Participation in the DRIP is optional. Those shareholders who did not enrol, or have not enrolled, in the DRIP are still entitled to receive their quarterly cash dividends on their Common Shares.

On July 25, 2014, the Company announced a reduction in the discount percentage for its DRIP. Eligible common shareholders were allowed to purchase additional Common Shares at a 5% discount to the average market price by reinvesting their dividends. The discount rate was reduced to 3% effective with the third quarter 2014 dividend. The Company reserves the right to limit the amount of new equity available under the DRIP on any particular dividend payment date. No assurances can be made that new Common Shares will be made available under the DRIP on a quarterly basis, or at all. Accordingly, participation may be prorated in certain circumstances. If on any dividend payment date the Company determines not to issue any equity under the DRIP, or the availability of new Common Shares is prorated in accordance with the terms of the DRIP, then participants are entitled to receive from the Company the full amount of their regular quarterly cash dividend for each share in respect of which the dividend is payable but cannot be reinvested under the DRIP in accordance with the applicable election.

On March 25, 2015, the Company announced the suspension of the DRIP following the April 2015 dividend payment. Since the Company's DRIP was introduced and as of December 31, 2018, 4,620,108 Common Shares have been issued pursuant to the DRIP at a weighted average price of $22.57. To date, no proration has occurred.

CAPITAL STRUCTURE

The Company's authorized share capital consists of an unlimited number of Common Shares, an unlimited number of Preference Shares issuable in series, and one Special Limited Voting Share. As of December 31, 2018, there were 101,872,618 Common Shares, 5 million Series 1 Shares, 6 million Series 3 Shares, 8 million Series 5 Shares, 8 million Series 7 Shares, 6 million Series 9 Shares and one Special Limited Voting Share outstanding.

Common Shares

Holders of Common Shares are entitled to one vote for each Common Share held on a ballot vote at all meetings of shareholders of the Company except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. Holders of Common Shares are entitled to receive, subject to the rights of the holders of another class of shares, any dividend declared by the Company and the remaining property of the Company on the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

Normal Course Issuer Bid

On February 19, 2019, the Company announced that the Toronto Stock Exchange had approved the Company's normal course issuer bid to purchase and cancel up to 9,034,925 of its outstanding Common Shares during the one year period from February 21, 2019 to February 20, 2020.

Pursuant to the rules of the Toronto Stock Exchange, the maximum number of Common Shares that may be purchased during the same trading day on the Toronto Stock Exchange is 85,702 Common Shares (being 25% of the average daily trading volume of Common Shares for the six months preceding the date of the normal course issuer bid notice to the Toronto Stock Exchange, which was equal to 342,811 Common Shares), subject to certain exceptions for block repurchases.

On February 16, 2018, the Company announced that the Toronto Stock Exchange had approved the Company's normal course issuer bid to purchase and cancel up to 9,309,476 of its outstanding Common Shares during the one-year period from February 21, 2018 to February 20, 2019. As of the date of this AIF, the Company has purchased 3,369,094 Common Shares at a weighted average price of $25.42.

Pursuant to the rules of the Toronto Stock Exchange, the maximum number of Common Shares that may be purchased during the same trading day on the Toronto Stock Exchange is 63,402 Common Shares (being 25% of the average daily trading volume of Common Shares for the six months preceding the date of the normal course issuer bid notice to the Toronto Stock Exchange, which was equal to 253,609 Common Shares), subject to certain exceptions for block repurchases.

Purchases are made on behalf of the Company by a registered broker through the facilities of the Toronto Stock Exchange at prevailing market prices pursuant to the rules of the Toronto Stock Exchange governing normal course issuer bids and/or through alternative Canadian trading platforms or otherwise as permitted by the Toronto Stock Exchange or an applicable securities regulatory authority.

Preference Shares

The Preference Shares may at any time and from time to time be issued in one or more series. Subject to the CBCA, the Board may fix, before the issue thereof, the number of Preference Shares of each series, the designation, rights, privileges, restrictions and conditions attaching to the Preference Shares of each series, including, without limitation, any voting rights, any right to receive dividends (which may be cumulative or non-cumulative and variable or fixed) or the means of determining such dividends, the dates of payment thereof, any terms and conditions of redemption or purchase, any conversion rights, any rights on the liquidation, dissolution or winding up of the Company, and any sinking fund or other provisions.

The Preference Shares of each series will, with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, rank on a parity with the Preference Shares of every other series and be entitled to preference over the Common Shares and any other shares ranking junior to the Preference Shares with respect to priority in payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of the Company.

On August 9, 2017, the Company issued 6 million Series 9 Shares at a price of $25.00 per Series 9 Share for aggregate gross proceeds of $150 million.

The Series 9 Shares pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending September 30, 2022. The dividend rate will reset on September 30, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.12%, provided that in any event, such rate shall not be less than 5.75%. The Series 9 Shares are redeemable by Capital Power, at its option, on September 30, 2022 and every five years thereafter.

The holders of the Series 9 Shares will have the right to convert all or any part of their Series 9 Shares into Cumulative Floating Rate Preference Shares, Series 10 (Series 10 Shares), subject to certain conditions, on September 30, 2022 and every five years thereafter. Holders of the Series 10 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 4.12%, as and when declared by the Board.

On October 4, 2016, the Company issued 8 million Series 7 Shares at a price of $25.00 per Series 7 Share for aggregate gross proceeds of $200 million.

The Series 7 Shares pay fixed cumulative dividends of $1.50 per share per annum, yielding 6.00% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2021. The first quarterly dividend of $0.3616 per share was paid on December 30, 2016 (for the initial period October 4, 2016 to

December 31, 2016). The dividend rate will reset on December 31, 2021 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 5.26%, provided that, in any event, such rate shall not be less than 6.00%. The Series 7 Shares are redeemable by the Company, at its option on December 31, 2021 and every five years thereafter.

The holders of Series 7 Shares will have the right to convert all or any part of their Series 7 Shares into Cumulative Floating Rate Preference Shares, Series 8 (Series 8 Shares), subject to certain conditions, on December 31, 2021 and five years thereafter. Holders of Series 8 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 5.26%.

On March 14, 2013, the Company issued 8 million Series 5 Shares at a price of $25.00 per Series 5 Share for aggregate gross proceeds of $200 million.

The Series 5 Shares paid fixed cumulative dividends of $1.125 per share per annum, yielding 4.50% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending June 30, 2018. The first quarterly dividend of $0.3329 per share was paid on June 28, 2013. The dividend rate reset on June 30, 2018 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.15%. The Series 5 Shares are redeemable by the Company, at its option, on June 30 of every fifth year after June 30, 2018.

The holders of Series 5 Shares had the right to convert all or any part of their Series 5 Shares into an equal number of Cumulative Floating Rate Preference Shares, Series 6 (Series 6 Shares), subject to certain conditions, on June 30, 2018. Following the conversion deadline on June 15, 2018, approximately 236,824 Series 5 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 6 Shares, as prescribed by the Company's articles of incorporation (as amended). Accordingly, 8,000,000 Series 5 Shares remain outstanding and there were no Series 6 Shares issued as at June 30, 2018. Effective June 30, 2018, the annual fixed dividend rate for the Series 5 Shares for the next five-year period was reset to 5.238% with a fixed cumulative dividend of $1.3095 per share per annum.

The holders of Series 5 Shares will have the right to convert their Series 5 Shares into Series 6 Shares, subject to certain conditions, again on June 30, 2023 and on June 30 of every fifth year thereafter. The holders of Series 6 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 3.15%.

On December 18, 2012, the Company issued 6 million Series 3 Shares at a price of $25.00 per Series 3 Share for aggregate gross proceeds of $150 million.

The Series 3 Shares paid fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2018. The first quarterly dividend of $0.3151 per share was paid on March 28, 2013 (for the initial period from December 18, 2012 to March 31, 2013). The dividend rate reset on December 31, 2018 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.23%. The Series 3 Shares are redeemable by the Company, at its option, on December 31 of every fifth year after December 31, 2018.

The holders of Series 3 Shares had the right to convert all or any part of their Series 3 Shares into an equal number of Cumulative Floating Rate Preference Shares, Series 4 (Series 4 Shares), subject to certain conditions, on December 31, 2018. Following the conversion deadline on December 17, 2018, approximately 47,270 Series 3 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 4 Shares, as prescribed by the Company's articles of incorporation (as amended). Accordingly, 6,000,000 Series 3 Shares remain outstanding and there were no Series 4 Shares issued as at December 31, 2018. Effective December 31, 2018, the annual fixed dividend rate for the Series 3 Shares for the next five-year period was reset to 5.453% with a fixed cumulative dividend of $1.36325 per share per annum.

The holders of Series 3 Shares will have the right to convert their Series 3 Shares into Series 4 Shares, subject to certain conditions, again on December 31, 2023 and on December 31 of every fifth year thereafter. The holders of Series 4 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 3.23%.

On December 16, 2010, the Company issued 5 million Series 1 Shares at a price of $25.00 per Series 1 Share for aggregate gross proceeds of $125 million.

The Series 1 Shares paid fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board, for the initial five-year period ending December 31, 2015. The first quarterly dividend of $0.3308 per share was paid on March 31, 2011 (for the initial period December 16, 2010 to March 31, 2011). The dividend rate reset on December 31, 2015 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%. The Series 1 Shares are redeemable by the Company, at its option, on December 31 of every fifth year after December 31, 2015.

The holders of Series 1 Shares had the right to elect to convert all or any part of their Series 1 Shares into Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares), subject to certain conditions, on December 31, 2015. Following the conversion deadline on December 16, 2015, approximately 930,800 Series 1 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 2 Shares, as prescribed by the Company's articles of incorporation (as amended). Accordingly, 5,000,000 Series 1 Shares remain outstanding and there were no Series 2 Shares issued as at December 31, 2015. Effective December 31, 2015, the annual fixed rate for the Series 1 Shares for the next five-year period was reset to 4.60%.

The holders of Series 1 Shares will have another opportunity to convert their Series 1 Shares into Series 2 Shares, subject to certain conditions, again on December 31, 2020 and on December 31 of every fifth year thereafter. The holders of Series 2 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 2.17% with a fixed cumulative dividend of $0.765 per share per annum.

Special Limited Voting Share

The authorized number of Special Limited Voting Shares is limited to one. The Special Limited Voting Share is held by EPCOR. The holder of the Special Limited Voting Share is entitled to receive notice of, to receive materials relating to, and to attend any meeting of Capital Power's shareholders; however, the holder of the Special Limited Voting Share is not, in such capacity, entitled to vote at any shareholder meeting except as provided by law or as described below.

The articles of the Company provide that any amendment to the articles of the Company to change the place in which the "Head Office" (as defined in the articles) is located to a place other than the City of Edmonton in the Province of Alberta or to change in any way the definition of "Head Office" and the related definitions set out in the articles, or any merger, amalgamation, arrangement, reorganization, liquidation or sale of all or substantially all of the property of the Company or similar transaction pursuant to which the resulting corporation or other successor to the Company or its business is not required to: (i) have its Head Office located in the City of Edmonton; (ii) have a definition of "Head Office" as set out in the articles; or (iii) have a Special Limited Voting Share in the capital of the resulting corporation or other successor to the Company having the same rights and restrictions as those relating to the Special Limited Voting Shares issued to the holder of the Special Limited Voting Share, must be approved by the holder of the Special Limited Voting Share, voting separately as a class, in addition to approval of the holders of the Common Shares. In addition, the jurisdiction of incorporation of the Company may not be changed, by continuance or otherwise; no amendment to the articles to increase the maximum number of authorized Special Limited

Voting Shares may be made; the rights, privileges, restrictions and conditions of the Special Limited Voting Share may not be amended; no exchange or creation of a right of exchange or right to acquire Special Limited Voting Shares may be effected; and no transaction, including any amendment to the articles, to effect an exchange, reclassification or cancellation of the Special Limited Voting Share may be undertaken, without approval by the holder of the Special Limited Voting Share, voting separately as a class.

The articles of the Company define "Head Office" to mean the office or offices at which: (i) the majority of the Company's senior "Executive Officers", which consist of the persons carrying out as a substantial part of their duties any of the functions of the chief executive officer, chief operating officer, chief financial officer, president, any executive vice-president, senior vice-president or general counsel of the Company, which majority shall include the chief executive officer, are located and from which they carry out the majority of their functions; and (ii) the majority of the "Executive Officers" are located and from which they carry out the majority of their functions (such majority including the Chief Executive Officer and the senior Executive Officers referred to in clause (i) above). The term "Executive Officers" is defined in the articles to include the senior Executive Officers referred to above; and (to the extent different from such senior Executive Officers) the persons, whether employed by the Company or any of its subsidiary entities, carrying out as a substantial part of their duties any of the functions of the chief executive officer, chief operating officer, chief financial officer, president, any executive vice-president or senior vice-president or general counsel, with respect to a substantial portion of the businesses carried on by the Company and its subsidiary entities, taken as a whole. The articles further require that the registered office of the Company be located in the City of Edmonton.

The Special Limited Voting Share carries no right for the holder to receive dividends. The holder of the Special Limited Voting Share has the right to receive, subject to any payment or distribution to holders of Preference Shares, in preference to the holders of Common Shares, the amount of $1.00 from the remaining property and assets of the Company upon the voluntary or involuntary liquidation, dissolution or winding-up of the Company.

EPCOR is also the holder of one special limited voting share of CPLPGP. The rights, privileges, restrictions and conditions of the special limited voting share of CPLPGP are substantially similar to those of the Special Limited Voting Share of the Company mutatis mutandis.

Debt Issuance

On January 23, 2019, Capital Power Corporation issued $300 million of senior unsecured medium-term notes due in 2026 with interest payable semi-annually at a rate of 4.986% commencing on July 23, 2019, pursuant to the New Indenture, as supplemented by a second supplemental Trust Indenture dated January 23, 2019.

On May 11, 2018, Capital Power Corporation filed a short form base shelf prospectus allowing for the offering of the following securities that may be issued pursuant to prospectus supplement, in one or more issuances in an aggregate principal amount not to exceed $3 billion: (i) common shares of the Company, (ii) preference shares of the Company, (iii) subscription receipts exchangeable for common shares and/or other securities of the Company; and (iv) debt securities of the Company. In addition, Capital Power Corporation filed a prospectus supplement to issue medium term notes due not less than one year from the date of issue, at prices and on terms determined at the time of issue, in an aggregate principal amount not to exceed $2 billion. All issuances may be made during the 25-month period that the prospectus remains valid. Any medium term notes issued under the base shelf prospectus and prospectus supplement filed in 2018 will be issued pursuant to the terms of the New Indenture.

On September 18, 2017, Capital Power Corporation issued $450 million of senior unsecured medium-term notes due in 2024 with interest payable semi-annually at a rate of 4.284% commencing on March 18, 2018, pursuant to the New Indenture, as supplemented by a first supplemental Trust Indenture dated September 18, 2017.

On September 13, 2016, Capital Power Corporation closed $160 million, 10-year Series C Senior Notes with Prudential Capital Group that mature in September 2026 (the Prudential Notes). The Prudential Notes bear an interest rate of 3.85% which will be paid semi-annually and rank pari-passu with the Company's other senior unsecured borrowings. The Note Purchase Agreement dated as of September 13, 2016, by and among CPC (as issuer) and the Purchasers (as defined therein) (the Prudential Agreement) prohibits the Company from making distributions if an event of default has occurred and is continuing, or would reasonably be expected to result from the distribution.

On May 3, 2016, the Company executed the New Indenture to support the issuance of senior unsecured medium term notes from time to time.

Effective December 18, 2015, the Company and CPLP completed the amendment of the Trust Indenture dated April 14, 2010 between CPLP and Computershare Trust Company of Canada as supplemented and amended from time to time (the CPLP Trust Indenture) and the exchange of all issued and outstanding $300 million principal amount 5.276% senior unsecured MTNs of CPLP due November 16, 2020 and all issued and outstanding $250 million principal amount 4.85% senior unsecured MTNs of CPLP due February 21, 2019 (the CPLP MTNs) for an equal principal amount of newly issued MTNs of Capital Power having financial and other terms that are the same as those attached to the CPLP MTNs and benefiting from a guarantee provided by CPLP (the Note Exchange Transaction). Upon the completion of the Note Exchange Transaction, CPLP was released and discharged from all obligations under or in respect of the CPLP Trust Indenture and the CPLP MTNs.

The New Indenture and the CPLP Trust Indenture (the Trust Indentures) do not limit the aggregate principal amount of MTNs that may be issued thereunder. Additional MTNs maturing at varying dates and bearing interest at different rates, in each case as determined by the Company, may be issued under the Trust Indentures. Under the Trust Indentures, the Company is restricted from incurring additional indebtedness, making distributions or redeeming or repurchasing partnership interests or subordinated debt unless it has a debt-to-capitalization ratio of not more than 75% at the time of (and after giving effect to) such actions.

On June 15, 2011, Capital Power U.S. Financing LP (US Financing LP), an indirect subsidiary of CPLP, closed a US$295 million private placement of senior notes (Senior Notes). The Senior Notes consist of two notes with 10 and 15-year terms. The 10-year Senior Note has a principal amount of US$230 million that matures in June 2021 with a coupon rate of 5.21%. The 15-year Senior Note has a US$65 million principal amount and matures in June 2026 with a coupon rate of 5.61%. The Senior Notes prohibit CPLP from making distributions if an event of default has occurred and is continuing, or would reasonably be expected to result from the distribution. On January 28, 2016, a Second Amending Agreement to the Note Purchase Agreement dated June 15, 2011 among US Financing LP, as issuer, CPLP, as parent guarantor, the Company, as additional guarantor, and each of the purchasers thereunder (the Note Purchase Agreement) was executed after receipt of the Note Holders' consent thereto. Pursuant to the Note Purchase Agreement, as amended, the Company has provided an additional parental guarantee of the obligations of US Financing LP under the Senior Notes and the Note Purchase Agreement. In addition, the Company has been substituted as the obligor for financial and reporting covenants (including the covenant to maintain a credit rating) under the Note Purchase Agreement and has also been substituted and/or added as the (or an) obligor for certain other covenants under the Note Purchase Agreement. The existing parental guarantee provided by CPLP remains in place.

Credit Facilities

Capital Power currently has two committed credit facilities under credit agreements among CPLP, CPLPHI and Capital Power (US Holdings) Inc. (as borrowers) and the Company (as covenantor) and a syndicate of lenders. Capital Power's credit facilities include an extendible syndicated facility of up to $700 million, with an accordion feature to increase the facility size by up to $300 million, an extendible revolving club credit facility of up to $300 million (both credit agreements were amended July 2018 and currently have an expiration date of July 9, 2023), and revolving demand credit facilities totalling $220 million (the Credit Facilities). The syndicated facility had previously been increased in July 2016 from $700 million to $755 million (using the accordion feature) to cover the amount of two non-extending lenders. These non-extending lenders were both withdrawn from the syndicate during the 2018 renewal and the limit was reduced back down to $700 million. Prior to that, during the July 2017 renewal process, Capital Power LP Holdings Inc. was added as a borrower under both the syndicated and club credit agreements, in order to support future projects residing beneath this corporation. Guarantees from the Company, CPLP and Capital Power (US Holdings) Inc. were provided to the lenders in the same form as those guarantees previously provided for the existing borrowers to ensure that any obligations of Capital Power LP Holdings Inc. remain pari passu with borrowings of all other Capital Power entities. Likewise, Capital Power LP Holdings Inc. guaranteed the obligations of its co-borrowers under the club and syndicated credit facilities. Capital Power LP Holdings Inc. guarantees were also provided per the Note Purchase Agreement (as defined above under "Capital Structure – Debt Issuance") and the Prudential Agreement (as defined above under "Capital Structure – Debt Issuance") to meet the pari passu covenants in both those agreements. In addition, Capital Power LP Holdings Inc. obtained a short-term credit facility of $150 million from an existing lender (the Side Car Facility) with terms, covenants, costs and intercorporate guarantees consistent with the Company's other credit facilities. The Side Car Facility has a term of 12 months and will mature in December 2019.

The syndicated and club credit facilities, as well as the Side Car Facility, require CPC to meet certain financial covenants, including maintaining a consolidated senior debt to consolidated capitalization ratio of not more than 0.65 to 1.0 as at the end of any fiscal quarter. In addition, in the event that CPC is assigned a credit rating by S&P that is less than BBB- or by DBRS that is less than BBB (low) (in each case assigned with a stable outlook), then CPC must also maintain a ratio of consolidated EBITDA (to consolidated interest expense (each as defined in each of the credit agreements) of not less than 2.5 to 1.0 as at the end of each fiscal quarter. The syndicated and club credit facilities also prohibit CPC from making distributions if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution.

Financial covenant calculations and financial reporting obligations are based on the Company's consolidated financial results (rather than CPLP financial reports).

Ratings

The following credit rating agencies have assigned the following credit ratings to the preferred shares of the Company and debt obligations of the Company:

Preferred Share Ratings

As at the date of this AIF, the Company has received a rating of Pfd-3 (low) with a stable trend for its preferred shares from DBRS and a rating of P-3 from S&P. Ratings are intended to provide investors with an independent measure of credit quality of an issue of securities.

The Company's preferred shares have been given a rating of P-3 by S&P. Such P-3 rating is the third highest of eight ratings used by S&P in its Canadian preferred share rating scale. According to S&P, a P-3 rating indicates that, although the obligation is less vulnerable to non-payment than other speculative issues, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions, which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. S&P further subcategorizes each rating by the designation of "high" and "low" to indicate where an entity falls within the rating category.

The Company's preferred shares have been given a rating of Pfd-3 (low) with a stable trend by DBRS. The Pfd-3 (low) rating is the third highest of six rating categories used by DBRS for preferred shares. According to DBRS, preferred shares rated Pfd-3 (low) are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. DBRS further subcategorizes each rating by the designation of "high" and "low" to indicate where an entity falls within the rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.

The rating by each of DBRS and S&P is not a recommendation to buy, sell or hold any securities of the Company in as much as such rating does not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised upward or downward or withdrawn entirely by either DBRS or S&P in the future if, in the judgment of either or both, circumstances so warrant. The ratings by DBRS and S&P may not reflect the potential impact of all risks related to the value of any of the securities of the Company. In addition, real or anticipated changes in the ratings assigned to the Company and its preferred shares may affect the market price or value of the securities of the Company.

Debt Ratings

Capital Power Corporation currently has a BBB (low) credit rating with a stable outlook for its Senior Unsecured Debt from DBRS and a BBB- Corporate Credit rating with a stable outlook from S&P. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities.

The BBB (low) Corporate Credit rating category is the fourth highest rating of DBRS's ten rating categories, which range from a high of AAA to a low of D. With the exception of the AAA and D categories, DBRS uses "high" or "low" designations to indicate the relative standing of the securities being rated within a particular rating category, while the absence of either a high or low designation indicates the rating is in the middle of the category. According to the DBRS rating system, long-term debt rated BBB is of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, however, may be vulnerable to future events.

The BBB- Corporate Credit rating assigned by S&P is the fourth highest rating of S&P's ten rating categories, which range from a high of AAA to a low of D. With the exception of the AAA and D categories, S&P may modify a rating using a plus (+) or minus (-) sign to show relative standing within the major rating categories. An obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An outlook is not necessarily a precursor of a rating change or future S&P credit action.

The credit rating by each of DBRS and S&P is not a recommendation to buy, sell or hold any securities of the Company in as much as such rating does not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised upward or downward or withdrawn entirely by either DBRS or S&P in the future if, in the judgment of either or both, circumstances so warrant. The credit ratings by DBRS and S&P may not reflect the potential impact of all risks related to the value of any of the securities of the Company. In addition, real or anticipated changes in the credit ratings assigned to the Company and its indebtedness may affect the market price or value of the securities of the Company.

The Company made payments to each of DBRS and S&P in connection with obtaining the aforementioned ratings and over the past two years has made payments in respect of certain other services provided to the Company by each of DBRS and S&P.

MARKET FOR SECURITIES

Trading Price and Volume

The Company's Common Shares trade on the Toronto Stock Exchange under the symbol of CPX. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2018 CPX Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$24.58	$23.06	$23.32	4,610,308
February	$24.38	$22.15	$23.70	4,992,780
March	$25.14	$23.53	$24.24	4,398,753
April	$25.08	$23.42	$24.38	3,290,747
May	$25.93	$24.21	$25.01	4,166,735
June	$26.00	$24.79	$25.23	3,682,724
July	$26.47	$25.12	$26.42	3,221,219
August	$27.84	$26.28	$27.36	4,508,464
September	$29.45	$26.99	$28.51	7,052,142
October	$29.79	$26.76	$27.32	9,471,087
November	$27.78	$25.81	$27.28	7,926,181
December	$28.82	$25.33	$26.59	8,058,833

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The Company's Series 1 Shares began trading on the Toronto Stock Exchange on December 16, 2010 under the symbol of CPX.PR.A. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2018 CPX.PR.A Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$17.25	$16.39	$17.00	61,677
February	$17.73	$16.89	$17.40	32,693
March	$17.73	$17.10	$17.54	45,143
April	$17.55	$17.03	$17.17	29,540
May	$17.61	$16.95	$17.30	57,179
June	$17.50	$17.01	$17.09	130,287
July	$17.49	$17.06	$17.45	42,059
August	$18.17	$17.40	$18.15	103,085
September	$18.30	$17.75	$18.13	51,146
October	$18.67	$16.85	$17.10	238,664
November	$17.20	$14.72	$15.10	63,473
December	$15.50	$13.65	$14.89	84,337

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The Company's Series 3 Shares began trading on the Toronto Stock Exchange on December 18, 2012 under the symbol of CPX.PR.C. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2018 CPX.PR.C Trading Statistics

Month	**Share Price**			**Volume Traded**
	High	**Low**	**Close**	
January	$22.79	$21.90	$22.71	171,355
February	$23.15	$22.21	$23.00	167,899
March	$23.22	$22.71	$23.17	77,599
April	$23.09	$22.72	$22.95	66,907
May	$23.79	$22.80	$23.42	97,176
June	$23.45	$22.16	$22.45	48,027
July	$23.36	$22.41	$23.28	104,595
August	$24.05	$23.28	$24.04	85,485
September	$24.23	$23.55	$23.96	38,089
October	$24.66	$22.82	$22.82	166,040
November	$23.24	$20.35	$21.30	74,923
December	$21.51	$19.90	$21.50	102,614

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The Company's Series 5 Shares began trading on the Toronto Stock Exchange on March 14, 2013 under the symbol of CPX.PR.E. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2018 CPX.PR.E Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$22.38	$21.51	$22.29	199,303
February	$22.90	$22.01	$22.73	58,955
March	$22.82	$22.15	$22.65	86,107
April	$22.60	$22.18	$22.45	88,591
May	$23.24	$22.25	$22.80	214,933
June	$22.93	$22.05	$22.20	72,881
July	$23.00	$22.20	$22.96	121,461
August	$23.72	$22.96	$23.70	525,830
September	$23.91	$23.21	$23.55	77,033
October	$24.11	$22.26	$22.55	165,161
November	$22.88	$19.89	$20.70	135,778
December	$21.35	$19.24	$21.22	107,714

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The Company's Series 7 Shares began trading on the Toronto Stock Exchange on October 4, 2016 under the symbol of CPX.PR.G. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2018 CPX.PR.G Trading Statistics

Month	**Share Price**			**Volume Traded**
	High	**Low**	**Close**	
January	$26.08	$25.84	$25.98	146,086
February	$26.10	$25.47	$26.00	74,194
March	$26.47	$25.75	$26.06	76,355
April	$26.08	$25.62	$25.71	195,648
May	$26.29	$25.66	$26.08	53,254
June	$26.25	$25.76	$25.80	57,830
July	$26.30	$25.69	$26.00	77,677
August	$26.30	$25.92	$26.15	45,056
September	$26.28	$26.00	$26.15	36,054
October	$26.41	$25.56	$25.95	226,653
November	$26.00	$25.15	$25.35	92,143
December	$25.50	$24.84	$25.20	110,188

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The Company's Series 9 Shares began trading on the Toronto Stock Exchange on August 9, 2017 under the symbol of CPX.PR.I. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2018 CPX.PR.I Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$25.90	$25.46	$25.59	87,058
February	$25.64	$25.10	$25.60	42,817
March	$25.80	$25.38	$25.48	60,867
April	$25.52	$25.25	$25.32	89,005
May	$26.10	$25.33	$25.75	38,721
June	$25.77	$25.33	$25.37	39,554
July	$25.67	$25.40	$25.61	27,124
August	$25.96	$25.52	$25.84	244,335
September	$25.90	$25.43	$25.75	40,885
October	$25.75	$25.00	$25.35	65,484
November	$25.50	$25.00	$25.25	97,244
December	$25.69	$24.60	$24.97	113,834

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DIRECTORS AND OFFICERS

Board of Directors

The name, place of residence, principal occupation, period of service as a member of the Board and membership in Board committees of each director of CPC are set forth in the following table as at December 31, 2018:

Name, Province / State and Country of Residence	**Director Since**	**Office Held**[(1)(2)] **Committee Membership**[(3)]	**Principal Occupation During Past Five Years**
Albrecht W.A. Bellstedt Canmore, Alberta, Canada Date of Birth: March 1949 Shares held:[(4)] Common Shares – 7,190	July 9, 2009	Director **Committees**: CGC&N HSE	Professional director from February 2007.
Doyle Beneby West Palm Beach, Florida, USA Date of Birth: October 1959 Shares held:[(4)] Nil	April 27, 2012	Director **Committees**: Audit HSE	Chief Executive Officer of Midland Cogeneration Venture from November 2018; prior thereto professional director from May 31, 2016; prior thereto, Chief Executive Officer, New Generation Power International, from October 2015; prior thereto, Chief Executive Officer, CPS Energy from July 2010.
Jill Gardiner Vancouver, BC, Canada Date of Birth: December 1958 Shares held:[(4)] Common Shares – 7,682	May 25, 2015	Director **Committees**: Audit CGC&N	Professional director from November 2010.
Kelly Huntington Indianapolis, Indiana, USA Date of Birth: September 1975 Shares held:[(4)] Nil	June 3, 2015	Director **Committees**: Audit HSE	Senior Vice President of Enterprise Strategy, OneAmerica Financial Partners, Inc., from July 2015; prior thereto, President & Chief Executive Officer, Indianapolis Power & Light Company, from June 2013.

Name, Province / State and Country of Residence	Director Since	Office Held[(1)(2)] Committee Membership[(3)]	Principal Occupation During Past Five Years
Philip Lachambre Edmonton, Alberta, Canada Date of Birth: December 1951 Shares held:[(4)] Common Shares – 15,720 Series 1 Shares – 800	July 9, 2009	Director **Committees**: Audit CGC&N	Professional director from July 2007 and President of PCML Consulting Inc. from February 2007.
Donald Lowry Edmonton, Alberta, Canada Date of Birth: September 1951 Shares held:[(4)] Common Shares – 11,000 Series 1 Shares – 9,000 Series 5 Shares – 2,000 Series 7 Shares – 800	July 9, 2009	Director and Chairman **Committees**:[(5)] CGC&N Audit HSE	Professional director from March 2013.
Katharine Stevenson Toronto, Ontario, Canada Date of Birth: June 1962 Shares held:[(4)] Common Shares – 4,000	April 3, 2017	Director **Committees**: Audit CGC&N	Professional director from 2007.
Keith Trent Charlotte, North Carolina, USA Date of Birth: October 1959 Shares held:[(4)] Nil	April 3, 2017	Director **Committees**: CGC&N HSE	Professional director from July 2015 and President of BK Trent LLC from January 1, 2016; prior thereto, Executive Vice President, Duke Energy, from 2005 to June 2015.
Brian Vaasjo Edmonton, Alberta, Canada Date of Birth: August 1955 Shares held:[(4)] Common Shares – 130,840	May 5, 2009	Director, President and Chief Executive Officer	President and Chief Executive Officer, Capital Power Corporation from July 2009.

Notes:

(1) The Board does not have an executive committee.
(2) Directors will hold office for a term expiring at the conclusion of the next annual meeting of shareholders of Capital Power or until their successors are elected or appointed and will be eligible for re-election.
(3) Board Committees: (i) Audit Committee, (ii) CGC&N Committee; and (iii) HSE Committee.
(4) Represents, as of December 31, 2018, the number of Common Shares, Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 7 Shares and Series 9 Shares, as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.
(5) As Chair, Mr. Lowry attends committee meetings in an ex-officio, non-voting capacity.

The Board has determined that all of the directors, except for Mr. Vaasjo, are independent within the meaning of applicable Canadian securities laws on the basis that they do not have any material direct or indirect relationship with the Company which could, in the view of the Board, be reasonably expected to interfere with the exercise of their independent judgment. Mr. Vaasjo is not considered independent as he is the President and Chief Executive Officer of the Company.

Executive Officers

CPC's officers are appointed by and serve at the discretion of the Board. The following table sets forth the names, place of residence, and position with Capital Power of each person who is an executive officer of Capital Power as at December 31, 2018:

Name, Province / State and Country of Residence	**Officer Since**	**Office Held**	**Principal Occupation During the last 5 Years**
Brian Vaasjo Edmonton, Alberta, Canada Date of Birth: August 1955 Shares held:(1) Common Shares – 130,840	May 1, 2009	President and Chief Executive Officer, Director	President and Chief Executive Officer, Capital Power Corporation from July 2009.
Bryan DeNeve Edmonton, Alberta, Canada Date of Birth: July 1965 Shares held:(1) Common Shares – 25,802	January 4, 2011	Senior Vice President, Finance and Chief Financial Officer since May 1, 2015; prior thereto Senior Vice President, Corporate Development and Commercial Services, since November 2012; prior thereto Senior Vice President, Commercial Services from January 2011	Senior Vice President, Finance and Chief Financial Officer, Capital Power Corporation since May 1, 2015; prior thereto Senior Vice President, Corporate Development and Commercial Services, Capital Power Corporation, from November 2012.
B. Kathryn Chisholm, Q.C. Edmonton, Alberta, Canada Date of Birth: May 1963 Shares held:(1) Common Shares – 18,593 Series 7 – 1,000	May 1, 2009	Senior Vice President, Chief Legal and Sustainability Officer since July 27, 2018; prior thereto Senior Vice President, Chief Legal and Sustainability Officer and Corporate Secretary since April 5, 2018; prior thereto Senior Vice President, Legal and External Relations and Corporate Secretary,	Senior Vice President, Chief Legal and Sustainability Officer since April 5, 2018; prior thereto Senior Vice President, Legal and External Relations, Capital Power Corporation from November 2012.

Name, Province / State and Country of Residence	Officer Since	Office Held	Principal Occupation During the last 5 Years
		from November 2012; prior thereto Senior Vice President, General Counsel and Corporate Secretary from May 2009	
Mark Zimmerman Edmonton, Alberta, Canada Date of Birth: November 1964 Shares held:[(1)] Common Shares – 9,511	November 2, 2015	Senior Vice President, Corporate Development and Commercial Services	Senior Vice President, Corporate Development and Commercial Services, Capital Power Corporation, from November 2015; prior thereto, Vice President, Corporate Development & Strategy, TransCanada, from August 1997.
Darcy John Trufyn Edmonton, Alberta, Canada Date of Birth: July 1955 Shares held:[(1)] Common Shares – 39,164	October 9, 2009	Senior Vice President, Operations, Engineering and Construction from November 2012; prior thereto Senior Vice President, Construction, Engineering and Project Management from October 2009	Senior Vice President, Operations, Engineering and Construction, Capital Power Corporation from November 2012.
Jacquelyn Marie Pylypiuk[(2)] St. Albert, Alberta, Canada Date of Birth: February 1969 Shares held:[(1)] Common Shares – 5,324	April 2015	Vice President, Human Resources	Vice President, Human Resources, Capital Power Corporation, from April 2015; prior thereto, Senior Manager, Talent Management, Capital Power Corporation, from March 2014; prior thereto, Senior Manager, Human Resources Business Partners, Capital Power Corporation, from September 2013.

Notes:

(1) Represents as of December 31, 2018 the number of Common Shares, Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 7 Shares, and Series 9 Shares, as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.

(2) Ms. Pylypiuk is an "executive officer" for the purposes of NI 51-102, but has not been appointed an officer of the Company by the Board.

As at December 31, 2018, the directors of the Company who are not also executive officers of the Company, as a group, beneficially owned, or controlled or directed, directly or indirectly, 45,592 Common Shares ($26.59 per share as at the close of trading on December 31, 2018 for a value of $1,212,291.28), which is less than 1% of the issued and outstanding Common Shares, 9,800 Series 1 Shares ($14.89 per share as at the close of trading on December 31, 2018 for a value of $145,922), which is less than 1% of the issued and outstanding Series 1 Shares, 2,000 Series 5 Shares ($21.22 per share as at the close of trading on December 31, 2018 for a value of $42,440), which is less than 1% of the issued and outstanding Series 5

Shares, and 800 Series 7 Shares ($25.20 per share at the close of trading on December 31, 2018 for a value of $20,160 which is less than 1% of the issued and outstanding Series 7 Shares.

As at December 31, 2018, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 274,826 Common Shares ($26.59 per share as at the close of trading on December 31, 2018 for a value of $7,307,623.34), which is less than 1% of the issued and outstanding Common Shares of the Company, 9,800 Series 1 Shares ($14.89 per share as at the close of trading on December 31, 2018 for a value of $145,922), which is less than 1% of the issued and outstanding Series 1 Shares, 2,000 Series 5 Shares ($21.22 per share as at the close of trading on December 31, 2018 for a value of $42,440), which is less than 1% of the issued and outstanding Series 5 Shares and 1,800 Series 7 Shares ($25.20 per share at the close of trading on December 31, 2018 for a value of $45,360 which is less than 1% of the issued and outstanding Series 7 Shares. The information as to the beneficial ownership of the Common Shares, Series 1 Shares, Series 5 Shares and Series 7 Shares, not being within the knowledge of the Company, has been confirmed by the directors and executive officers individually.

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

As at December 31, 2018, except as noted below, and to the knowledge of the Company, no director, executive officer or controlling security holder of the Company is, or within the ten years prior to the date hereof, has been, a director or executive officer of any other issuer that, while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days;

(ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the corporation being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Albrecht Bellstedt ceased being a director of Sun Times Media Group, Inc. (formerly Hollinger International Inc.) in June of 2008. Sun Times Media Group, Inc. went into Chapter 11 bankruptcy protection under the U.S. Bankruptcy Code in 2009.

Keith Trent was a member of the management committee of Crescent Resources, LLC, a real estate joint venture between Duke Energy Corporation and Morgan Stanley Real Estate Fund. In 2009, subsequent to Mr. Trent having ceased to be a member of the management committee, Crescent Resources, LLC went into chapter 11 bankruptcy protection under the U.S. Bankruptcy Code.

Conflicts of Interest

Certain directors and officers of the Company are associated with other reporting issuers or other corporations which may give rise to conflicts of interest. In accordance with corporate laws, directors who are a party to, are a director or officer of a party to, or have a material interest in any person who is a party to a material contract or material transaction or a proposed material contract or material transaction with the Company are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract or transaction. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Company.

Capital Power uses a subsidiary of Kelly Huntington's employer, OneAmerica Financial Partners, Inc., as the record keeper for its US 401k plan. Ms. Huntington was not involved in the selection of the record keeper nor in any ongoing evaluation.

Conflicts, if any, will be subject to the procedures and remedies available under the CBCA. The CBCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the CBCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Management is not aware of any existing or contemplated legal proceedings material to Capital Power to which it is a party or to which its property is subject except as described below.

Milner Power Inc. (Milner) Loss Factor Complaint

Capital Power is participating in a proceeding before the AUC to re-hear a complaint originally filed by Milner in 2005 against the AESO's loss factor calculation methodology (LFM). The AUC initially rejected the complaint in 2005, but Milner appealed the decision in 2006. The Court of Appeal issued a ruling in 2010 directing the AUC to re-hear the complaint.

The LFM is used to calculate generator-specific line loss factors and forms the basis for certain transmission charges paid by Alberta generators. Milner alleged that the existing LFM, developed by the AESO in consultation with stakeholders in 2005 and implemented January 1, 2006, did not comply with applicable regulations. Milner advocated for the adoption, retroactively back to 2006 and on a go-forward basis, of an alternative LFM that would increase the line loss charges to Alberta generating units generally further away from load centres (including Genesee, Sundance, and Keephills) and proportionately decrease the charges to those that are closer in proximity to load (including Shepard). However, some facilities may see little to no impact.

In 2015, the AUC determined that the LFM did not comply with applicable regulations. The AUC also determined that it has the jurisdiction to direct retroactive adjustments to loss factor charges and credits back to January 1, 2006. Capital Power and other parties have challenged this and other determinations to the Alberta Court of Appeal.

On November 30, 2016, the AUC approved a new methodology for determining loss factors on a prospective basis effective January 2017.

A final AUC proceeding was held in 2017 to establish the methodology to be used in determining retroactive line loss adjustments. The AUC issued a decision in December 2017 and concluded that the prospective methodology be adapted for determining retroactive adjustments back to January 2006. AESO implementation activities were held over the course of 2018 and are expected to continue well into 2019. However, no final historic loss factors using the approved methodology for invoicing purposes have been filed to date. According to AESO estimates issued on December 20, 2018, the complete set of retrospective loss factors under the approved methodology for historic periods is expected to be made available in August of 2019 but may be delayed.

With the outstanding phases of the AUC process relating to the Milner complaint largely complete, the Alberta Court of Appeal resumed the appeal process in June of 2018. A Court of Appeal hearing was held in June of 2018 to consider whether permission to appeal will be granted. On December 20, 2018, the Court of Appeal issued a decision rejecting the permission to appeal applications that sought to overturn the AUC's finding on jurisdiction to issue retroactive tariff adjustments. However, the Court of Appeal has yet to issue a decision on the applications that seek, among other things, to challenge the aspect of the AUC's 2017 decision that establishes the recipient of adjustment invoices. Until this decision is released however, the potential process and timing for the appeal remains to be fully determined.

Given the foregoing, estimates of Capital Power's potential exposure to retroactive adjustments for line loss charges are preliminary, remain highly uncertain and subject to change until final loss factors have been issued by the AESO and the regulatory and legal processes to consider the new and outstanding applications currently underway have been completed. See "Regulatory Overview – Alberta – Transmission Line Losses" and "Risk Factors".

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and preferred shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal holder of securities or any associate or affiliate of the foregoing has, or has had, within the three most recently completed financial years, any material interest in any transaction, or in any proposed transactions that has materially affected or will materially affect the Company or been indebted to the Company, except for routine indebtedness, other than as set forth in the AIF. See "Material Contracts".

EPCOR holds the one issued and outstanding Special Limited Voting Share. The Special Limited Voting Share confers on the holder the right to vote separately as a class in connection with certain amendments to the articles of the Company, including an amendment to change or permit the change of the location of the head office of the Company from the City of Edmonton, Alberta. EPCOR has undertaken to its sole shareholder, the City of Edmonton that it will not exercise, dispose of or otherwise relinquish any rights it has under the Special Limited Voting Share without the consent of the City of Edmonton.

MATERIAL CONTRACTS

The following are the only material contracts, other than those contracts entered into in the ordinary course of business, which Capital Power has entered into since its incorporation on May 1, 2009 and within the most recently completed financial year.

- Master Separation Agreement between EPCOR and Capital Power dated June 25, 2009 (Master Separation Agreement)
- Social Objectives Agreement among EPCOR, 7166575 Canada Inc. and The City of Edmonton dated May 5, 2009, as amended on February 4, 2014 (Social Objectives Agreement)
- Amended and Restated Shareholder Rights Plan Agreement between CPC and Computershare Trust Company of Canada dated April 22, 2016 (Amended and Restated Rights Plan Agreement)
- Off-Coal Agreement between Capital Power, certain of its subsidiaries and the Province of Alberta dated November 24, 2016 (Off-Coal Agreement)

The following section provides a summary of these agreements. Copies of the above material agreements may be viewed on SEDAR at www.sedar.com.

Master Separation Agreement

The Master Separation Agreement contains the key provisions related to the separation of the business of the Company from EPCOR and the transfer of the power generation business from EPCOR to the Company pursuant to the Reorganization. All of the Company's and EPCOR's covenants and agreements in the Master Separation Agreement will survive indefinitely, subject to applicable laws. Certain of the principal provisions of the Master Separation Agreement relate to:

- The ownership and transfer of assets, including the separation of the Company's assets and assumption of liabilities from EPCOR through transfer agreements that the Company and / or CPLP have entered into with EPCOR. The assets constituting the business of Capital Power were transferred to the Company and CPLP on an "as is", "where is" basis without any representations or warranties, express or implied, as to its condition, quality, merchantability or fitness and the Company and / or CPLP, as applicable, bear the economic and legal risks if any conveyance proves to be insufficient to vest good and marketable title in such transferee;

- Capital Power indemnifying EPCOR, each of EPCOR's controlled subsidiaries, and each of their respective directors, officers, employees, consultants, advisers and agents from all losses they may suffer relating to, arising out of, or in respect of certain circumstances or events, whether such losses arise or accrue prior to, on or following the closing of the Reorganization, including Capital Power's business or future business or any liabilities arising out of or related to such business or Capital Power's assets; and

- EPCOR indemnifying Capital Power, each of Capital Power's controlled subsidiaries, and each of their respective directors, officers, employees, consultants, advisers and agents from all losses they may suffer relating to, arising out of, or in respect of certain circumstances or events, whether such losses arise or accrue prior to, on or following the closing of the Reorganization, including EPCOR's business or future business or any liabilities arising out of or related to such business or EPCOR's assets (excluding any liability arising out of the business of Capital Power).

Social Objectives Agreement

Pursuant to the Social Objectives Agreement, the Company agreed to maintain its head office in the City of Edmonton in the Province of Alberta and to maintain at least 350 employees based in the City of Edmonton for a period of 25 years following completion of the IPO. In February 2014, the Social Objectives Agreement was amended by agreement among the Company, EPCOR, and the City of Edmonton to replace the requirement for the Company to maintain at least 350 employees in the City of Edmonton with a requirement for the Company to maintain two-thirds of its corporate shared service employees in the City of Edmonton. See "Capital Structure – Special Limited Voting Share".

Amended and Restated Shareholder Rights Plan Agreement

On November 20, 2012, the Board approved the adoption of a shareholder rights plan (2012 Rights Plan). The 2012 Rights Plan Agreement, dated November 20, 2012 between the Company and Computershare Trust Company of Canada, as rights agent, and the 2012 Rights Plan were confirmed and ratified by the Company's shareholders at its annual meeting of shareholders on April 26, 2013. On February 18, 2016, the Board resolved to continue the 2012 Rights Plan and to adopt an Amended and Restated Shareholder Rights Plan Agreement which was approved by shareholders at the April 22, 2016 annual meeting of shareholders of Capital Power (Rights Plan). The terms of the Rights Plan are the same in all material respects as the 2012 Rights Plan, but for certain minor amendments described below.

The following were the amendments to the 2012 Rights Plan contained within the Rights Plan, as amended and restated:

- The definition of "Expiration Time" in the Rights Plan, and the requirement for future shareholder approval to ratify the continued existence of the Rights Plan, were simplified to specify that requisite shareholder approval will be obtained to continue the rights plan at every third annual general meeting of shareholders or else the Rights Plan will terminate.

- The definition of "Permitted Lock-Up Agreement" was amended to include Convertible Securities (as such term is defined in the Rights Plan) as securities of Capital Power that may be the subject of a permitted lock-up agreement, in addition to the Voting Shares.

- The definition of "Permitted Bid" was amended to be the longer of 60 days or the minimum take-over bid deposit period prescribed by law. Under current securities regulations, this will not result in any change to the length of a permitted bid. Due to certain announced changes to securities law governing take-over bids, this language was added to contemplate changes to the law.

- Certain other amendments of a non-substantive, "housekeeping" nature were made to account for the fact that there are no longer any Exchangeable LP Units or Special Voting Shares outstanding. These changes provide greater clarity and consistency.

The Rights Plan authorizes the issuance of one right (Right) in respect of each Common Share (the Voting Shares). The Rights initially trade with and are represented by the certificates representing the Voting Shares, and until such time as the Rights separate from the Voting Shares and become exercisable, Rights certificates will not be distributed to shareholders.

Each Right is initially attached to and will trade with the Voting Shares in respect of which it was issued. The Rights will separate from the Voting Shares to which they are attached and become exercisable after the time (Separation Time) which (subject to the Board deferring the Separation Time) is the close of business ten trading days following the date of public announcement that a person has become an Acquiring Person (as defined below) or announces an intention to make a take-over bid that is not in compliance with the provisions of the Rights Plan.

Upon the occurrence of any transaction or event in which a person (an Acquiring Person), including associates and affiliates and others acting jointly or in concert, acquires (other than pursuant to a Permitted Bid (as defined in the Rights Plan) or another exemption available under the Rights Plan) Beneficial Ownership (as defined in the Rights Plan) of 20% or more of the outstanding Voting Shares of the Company (a Flip-in Event), any Rights held by an Acquiring Person will become void and the Rights held by all other holders of Rights will permit such holders to purchase Common Shares at a substantial discount to their then prevailing market price.

A bidder can make a take-over bid and acquire Common Shares of the Company without triggering a Flip-In Event under the Rights Plan if the take-over bid qualifies as a Permitted Bid. The Rights Plan also allows for a competing Permitted Bid (Competing Permitted Bid) to be made while a Permitted Bid is in existence, as long as the Competing Permitted Bid satisfies certain conditions.

With the consent by majority vote of Independent Shareholders (as defined in the Rights Plan) prior to the Separation Time, or the consent by majority vote of the independent holders of Rights after the Separation Time, the Board may redeem all of the outstanding Rights at a price of $0.00001 per right. With the consent by majority vote of Independent Shareholders prior to the Separation Time, the Board may waive the application of the Rights Plan to a Flip-in Event that occurs other than by means of a takeover bid made by way of a takeover bid circular sent to all holders of Voting Shares. Without the approval of shareholders or holders of Rights, the Board may waive the application of the Rights Plan to a Flip-in Event that occurs by means of a takeover bid made by way of a takeover bid circular sent to all holders of Common Shares.

The foregoing description of the Rights Plan is qualified entirely by the full text of the Rights Plan. On February 15, 2019, the Board resolved to continue the Rights Plan. If the Rights Plan is approved by the shareholders at the 2019 annual meeting of shareholders of Capital Power, the Rights Plan will expire at the close of business on the date of the 2022 annual meeting of shareholders, unless otherwise extended by a further vote of shareholders.

Off-Coal Agreement

On November 24, 2016, Capital Power and the Province of Alberta entered into the Off-Coal Agreement. The parties agreed that Capital Power's coal-fired electricity generation plants will cease coal-fired emissions on or before December 31, 2030, and Capital Power is to receive cash payments from the Province of $52.4 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. The Government of Alberta has conducted an audit on the calculation of net book values driving the compensation payments and has withheld $2 million from the 2017 payment. The Company is disputing the withholding, but has reduced the amounts recorded related to the compensation stream to reflect the uncertainty around the withheld portion of the 2017 payment. This has resulted in a reduction of $1 million to the government compensation amount recorded in other income to $51 million for 2017. Capital Power has also agreed to continue to participate in the Alberta electricity market, support the local communities surrounding the coal facilities through 2030, and fulfill its pension and other commitments to employees.

INTERESTS OF EXPERTS

The Company's auditors are KPMG LLP, Chartered Professional Accountants, 10125 – 102 Street, Edmonton, Alberta T5J 3V8. KPMG LLP has confirmed that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

AUDIT COMMITTEE

Audit Committee Mandate

The responsibilities and duties of the Audit Committee are set out in the Committee's Terms of Reference, provided in Appendix A to this AIF.

Composition of the Audit Committee

As at December 31, 2018, the Audit Committee was composed of Philip Lachambre (Chair), Doyle Beneby, Jill Gardiner, Kelly Huntington and Katharine Stevenson. As Chair of the Board, Donald Lowry also attends Audit Committee meetings in an ex-officio, non-voting capacity. The Board has determined that all members of the Audit Committee are "independent" and "financially literate" as such terms are defined under applicable Canadian securities law and mandated under the Board terms of reference. See "Directors and Officers".

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The Board based the determination regarding financial literacy on the education and breadth and depth of experience of each Audit Committee member, as summarized in the following table:

AC Member	**Relevant Education and Experience**
Philip Lachambre	• formerly Executive Vice President and Chief Financial Officer of Syncrude Canada Ltd. • holds a Bachelor of Commerce degree from the University of Alberta, and is a graduate of the Executive Management Program of the University of Western Ontario • has previously served as the Chair of the Audit Committee of Flint Energy Services Ltd., PowerComm Inc. and GLM Industries LP
Doyle Beneby	• currently Chief Executive Officer of Midland Cogeneration Venture (the largest natural gas fired combined electrical energy and steam energy generating plant in the U.S.) since November 2018 • formerly served as Chief Executive Officer of New Generation Power International (an international independent renewable energy company) from 2015 to 2016 • formerly served as President and Chief Executive Officer of CPS Energy (the largest municipally-owned gas and electric utility company in the U.S.) from 2010 to 2015 • formerly served as Senior Vice President and Acting President of Exelon Corporation in 2009 and 2010 • has an MBA
Jill Gardiner	• member of the audit committee of Capstone Mining Corp. • past chair of the board of directors of Turquoise Hill Resources Ltd. and a past member and former chair of its Audit Committee • previously a member (or chair) of the audit committees of Timber Investments Ltd., The Banff Centre and SAIT Polytechnic • previously spent over 20 years in the investment banking industry, most recently as Managing Director and Regional Head, British Columbia, for RBC Capital Markets • has previously held various positions in corporate finance, mergers and acquisitions, and debt capital markets • holds an MBA (with a major in finance and accounting) from Queen's University • past lecturer in corporate finance at the University of Victoria
Kelly Huntington	• currently Senior Vice President of Enterprise Strategy for OneAmerica Financial Partners, Inc., which includes responsibility for internal audit, and also is a member of the board for five related entities • formerly President & Chief Executive Officer, and Senior Vice President & Chief Financial Officer, for Indianapolis Power & Light Company (IPL) and a Board member • formerly Vice President, Financial Planning & Analysis for The AES Corporation, a Fortune 200 global power company • has previously held a variety of positions in investment banking, private equity, financial analysis, investor relations and risk management • holds an MBA from Northwestern University's Kellogg School of Management, and is a Chartered Financial Analyst

AC Member	Relevant Education and Experience
Katharine Stevenson	• member of the audit committees of Open Text Corporation and CAE Inc. • previously chair of the audit committees of CAE Inc. and OSI Pharmaceuticals, Inc. • formerly a senior financial executive/Global Treasurer of Nortel Networks from 1997 to 2005 • previously held progressively senior finance roles in corporate and investment banking at J.P. Morgan and Company from 1984 to 1995 • has earned her ICD.D designation from the Institute of Corporate Directors

Policies and Procedures for the Engagement of Audit and Non-audit Services

Under its Terms of Reference, before Capital Power engages the external auditor for additional audit or non-audit services, the Audit Committee must pre-approve that engagement. If, for reasons of timing, pre-approval is not possible and it is not possible to wait until the next scheduled Audit Committee meeting, the Chair of the Audit Committee has the delegated authority to pre-approve non-audit services as long as the individual engagement fees are projected to be less than $100,000, subject to an annual maximum approval limit of $250,000. Any pre-approval must be reported to the Audit Committee for ratification at its next meeting. In 2018, the Chair of the Audit Committee pre-approved non-audit related services provided by the external auditors in the amount of $30,000. The services pre-approved by the Chair related to Capital Power's Diversity & Inclusion Committee and included an assessment of the current state of diversity and inclusion within Capital Power against leading industry practice, followed by high-level recommendations to address any gaps. The committee chair's approval of those expenses was ratified by the Audit Committee.

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Auditor's Fees

KPMG LLP has served as the Company's auditors since its incorporation. Fees accrued by KPMG LLP to the Company for the year ended December 31, 2018 in respect of the Company and the Company's subsidiaries were approximately $1.2 million as detailed below.

	Twelve Months Ended December 31, 2018 ($ Millions)	**Twelve Months Ended December 31, 2017 ($ Millions)**
Audit Fees	1.1	1.4
Audit Related Fees	-	-
Tax fees	-	-
All Other fees	0.1	0.1
Total	**1.2**	**1.5**

Audit fees – Audit fees billed are for professional services rendered for the audit and review of the financial statements of the Company or services provided in connection with statutory and regulatory filings and providing comfort letters associated with securities documents.

Audit related fees – Audit related fees are for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements and are not reported under audit fees listed above.

Tax fees – Tax fees are tax-related services for review of tax returns, assistance with questions on tax audits, and tax planning.

All other fees – All other fees are fees for operational advisory and risk management services and non-securities legislative and regulatory compliance work.

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Other Committees

Apart from the Audit Committee, the Board has established: (i) the CGC&N Committee to oversee matters relating to corporate governance, compensation and nomination; and (ii) the Health, Safety and Environment Committee to oversee matters relating to the impact of the Company's operations on the environment and on workplace health and safety. Mr. Lowry, the Chair of the Board, is a non-voting ex-officio member of all committees. The members of these committees as at December 31, 2018 were as follows:

CGC&N Committee

Ms. Jill Gardiner, Chair
Mr. Albrecht Bellstedt
Mr. Philip Lachambre
Ms. Katharine Stevenson
Mr. Keith Trent
Mr. Donald Lowry (ex-officio)

Health, Safety and Environment Committee

Mr. Doyle Beneby, Chair
Mr. Albrecht Bellstedt
Ms. Kelly Huntington
Mr. Keith Trent
Mr. Donald Lowry (ex-officio)

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ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com and on the Company's website at www.capitalpower.com.

Additional financial information is provided in the Company's annual audited consolidated financial statements and MD&A for the year ended December 31, 2018.

The "Risks and Risk Management" section of the Company's MD&A for the year ended December 31, 2018 is incorporated herein by reference and is available on SEDAR.

The Company's material change reports are incorporated herein by reference and is available on SEDAR.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensations plans, if applicable, is contained in the Company's information circular for its most recent annual meeting of securityholders that involved the election of directors.

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APPENDIX "A"

AUDIT COMMITTEE

TERMS OF REFERENCE

A. OVERVIEW AND PURPOSE

1. The Audit Committee (the "Committee"), except to the extent otherwise provided by law, is responsible to the Board of Directors (the "Board") of Capital Power Corporation (the "Corporation"). The Committee provides assistance to the Board in fulfilling its oversight responsibility to shareholders of the Corporation, the investment community and others in relation to the integrity of the Corporation's financial statements, financial reporting processes, systems of internal accounting and financial controls, the risk identification assessment conducted by Management and the programs established by Management and the Board in response to such assessment, the internal audit function and the external auditors' qualifications, independence, performance and reports to the Corporation. In addition, the Committee monitors, evaluates, advises or makes recommendations, in accordance with these terms of reference and any other directions of the Board, on matters affecting the financial and operational control policies and practices relating to the Corporation, including the external, internal or special audits thereof. Finally, the Committee monitors, evaluates, advises or makes recommendations, in accordance with these terms of reference and any other directions of the Board, on matters related to the raising of capital and capital allocation.

2. Management is responsible for preparing the interim and annual financial statements of the Corporation and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly. The Committee is responsible for reviewing Management's actions and has the authority to investigate any activity of the Corporation. The primary responsibilities of the Committee include:

   a) assessing the processes related to identification of the risks and effectiveness of the Corporation's control environment, as they relate to the production of financial statements and other publicly disclosed financial information;

   b) overseeing and monitoring the Corporation's financial reporting;

   c) evaluating the Corporation's internal control systems for financial reporting;

   d) overseeing the audit of the Corporation's financial statements;

   e) overseeing and monitoring the qualifications, independence and performance of the Corporation's external auditors;

   f) maintaining direct lines of communication between the Corporation's external auditors, its internal auditing department, Management and the Board;

   g) evaluating the internal and external, and any special, audit processes; and

   h) monitoring and evaluating the Corporation's financial risks.

3. The Committee will have unrestricted access to the Corporation's personnel and documents, including its internal auditors, and will be provided with the resources required to carry out its responsibilities. The Committee is authorized to retain, at the expense of

the Corporation, independent outside advisors and consultants as it sees fit to assist it in carrying out its duties and responsibilities.

4. The Committee will be the direct report for the external auditors, will evaluate their performance and will recommend their compensation to the Board.

B. STRUCTURE AND MEMBERSHIP

1. The Committee will be composed of such number of directors as may be specified by the Board from time to time, which number will be not less than three.

2. At the first meeting of the Board following the Corporation's annual general meeting, Committee Members (Committee Members) and the Committee Chair will be appointed by the Board on the recommendation of the Corporate Governance, Compensation and Nominating Committee (the "CGCN Committee").

3. All Committee Members will be independent and unrelated, as set forth in all applicable securities laws and regulations or the rules or guidelines of any stock exchange on which the securities of the Corporation are listed for trading (including, without limitation, NI 52-110, as implemented by the Canadian Securities Administrators and as amended or replaced from time to time), and have no relationship with the Corporation that may materially interfere with the ability of each Committee member to act with a view to the best interests of the Corporation.

4. All Committee Members will be financially literate (as such term is defined in NI 52 110). At least one member of the Committee will have a professional accounting designation or equivalent financial expertise as determined by the Board.

C. DUTIES AND RESPONSIBILITIES

The Committee will:

1. Review the Corporation's annual audited financial statements including the notes thereto, management's discussion and analysis, earnings press releases and annual information forms before such documents are submitted to the Board for approval, including any report or opinion to be rendered in connection therewith, and make recommendations as to their approval by the Board.

2. Review, and make recommendations for subsequent approval by the Board, the Corporation's quarterly financial statements including the notes thereto, management's discussion and analysis and earnings press releases of the Corporation.

3. Review with Management, the external auditors and, if necessary, internal and external legal counsel, any material litigation, claim, compliance issues, or regulatory or other contingency that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these will be, or have been, disclosed in the Corporation's financial statements.

4. Review on a quarterly basis with the CFO and General Counsel, and if necessary, external legal counsel, the status of all material litigation, claims, compliance issues, or regulatory or other contingencies faced by the Corporation.

5. Review, or establish procedures for the review of, all public disclosure documents containing audited, unaudited or forward-looking financial information before release by the Corporation, including any prospectus, management information circulars, offering memoranda, annual reports, management certifications, management's discussion and analysis, annual information forms and press releases.

6. As required, review Management's plans and strategies around investment practices, banking performance, treasury risk management, corporate finance and financial capital allocation, including, without limiting the generality of the foregoing, reviewing financing transactions such as offerings of debt or equity securities and obtaining, amending or extending credit facilities, and recommending the same to the Board.

7. Assess Management's procedures to ensure compliance by the Corporation with its loan and indenture covenants and restrictions, if any.

8. Monitor the appropriateness of the accounting policies and practices and financial reporting used by the Corporation, review any actual and prospective significant changes to such accounting policies and practices financial reporting to be adopted by the Corporation and review and assess any new or proposed developments in accounting and reporting standards that may affect or have an impact on the Corporation.

9. Review and recommend the nomination of the external auditors to the Board for appointment by the shareholders at the Corporation's annual general meeting. In connection therewith, the Committee will review the experience and qualifications of the external auditors' senior personnel who are providing audit services to the Corporation and the quality control procedures of the external auditors.

10. Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the independence of the Corporation's external auditors, including, without limitation: (i) requesting, receiving and reviewing, at least annually, a formal written report from the external auditors delineating all relationships that may reasonably bear on the independence of the external auditors with respect to the Corporation; and (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors. Following receipt and review of the external auditors' report and discussion with the external auditors, recommending that the Board, in response to the relationships or services disclosed in the report, take appropriate action to satisfy itself of the external auditors' independence.

11. Discussing with the Board whether, due to the passage of time or for other reasons, it would be appropriate to change the Corporation's external auditors or the audit engagement partner and, after consultation with appropriate Management, recommending either that the external auditors be changed or retained for each future fiscal year.

12. Review and recommend to the Board for approval the compensation paid to the external auditors on an annual basis.

13. Review and pre-approve all non-audit services performed by the external auditors in relation to the Corporation and its subsidiaries. If, due to timing issues, the pre-approval of non-audit services must be expedited and it is not practical to wait until the next scheduled Committee meeting, the Chair is delegated, on behalf of the Committee, to pre-approve the non-audit services when the individual engagement fees are projected to be less than $100,000, subject to an annual maximum approval limit of $250,000, and any such pre-approval will be reported to the Committee for ratification at its next meeting.

14. Oversee the work of the external auditor, including reviewing and approving the planning of the annual audit and reviewing the results thereof with the external auditors, including:

    a) approving the auditors' engagement letters;

    b) approving the scope of the audit, including materiality, audit reports required, area of audit risk, timetable and deadlines;

c) reviewing with the external auditors the quality, not just the acceptability, of the accounting principles applied in the Corporation's financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;

d) reviewing the post-audit management letter together with Management's responses;

e) reviewing any other matters the external auditors bring to the attention of the Committee;

f) resolving disagreements with Management regarding financial reporting;

g) reviewing accruals, reserves and estimates which could have a significant effect on financial results;

h) reviewing the use of any "pro forma" or "adjusted" information not in accordance with generally accepted accounting principles (GAAP); and

i) reviewing interim review engagement reports.

The Corporation's external auditors are ultimately accountable to the Board and the Committee as representatives of the shareholders of the Corporation, and will report directly to the Committee.

15. Review the rationale for any proposed change in auditors which is not initiated by the Committee or the Board.

16. Review reports from external auditors respecting their internal quality control procedures, peer reviews and investigations by governmental or professional authorities.

17. Obtain and review annually, prior to the completion of the external audit: (a) a report from the external auditors describing: (i) all critical accounting policies used by the Corporation in the preparation of its annual and interim financial statements; (ii) all alternative treatments of financial information within GAAP that have been discussed with Management; (iii) the ramifications of the use of such alternative treatments; and (iv) the treatment preferred by the external auditors; and (b) all other material written communications.

18. Obtain reasonable assurance from discussions with and/or reports from Management and reports from external and internal auditors that the Corporation's accounting systems are reliable and that the prescribed internal controls are operating effectively.

19. Assess whether Management has implemented policies ensuring that the Corporation's financial risks are identified and that controls are adequate, in place and functioning properly. In connection therewith, as part of the financial risk assessment, Management will prepare tax compliance and planning strategies annually for review by the Committee, including a review of any tax reserves.

20. Monitor compliance with the Corporation's Ethics Policy (the "Ethics Policy") and ensure Management Compliance Certificates are received from Management quarterly.

21. Meet with the external auditors, at least annually and when requested by the external auditors, without Management representatives present.

22. Meet with the internal auditors, at least annually or as requested by the internal auditors, without Management representatives present.

23. Review and ensure that appropriate liaison and cooperation exists where necessary between the external auditors and the internal auditors, and provide a direct line of communication between the external and internal auditors, the Committee and the Board.

24. Review the responses of Management to information requests from government or regulatory authorities in respect of filing documents required under securities legislation, which may affect the financial reporting of the Corporation.

25. Review and approve the annual internal audit plan, including the mandate, staffing, scope and objectives of the internal audit department, and receive and review all financial internal audit reports issued in relation thereto.

26. Receive and review all follow-up action or status reports relating to the non-financial recommendations of the external auditor, and the internal auditor.

27. Obtain such information and explanations regarding the accounts of the Corporation as the Committee may consider necessary and appropriate to carry out its duties and responsibilities.

28. Annually review the performance, budget and independence of the internal audit function and direct the CFO to make any changes necessary.

29. Establish procedures for receiving, retaining and responding to complaints relating to accounting, internal accounting controls or auditing matters, on a basis that protects the confidentially of the complainant.

30. Review and approve the hiring policies regarding employees and former employees of the present and former external auditors.

31. Periodically assess procedures for the review of disclosure of financial information, extracted or derived from the Corporation's financial statements.

32. Review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments, and ensure that they are appropriately reflected in the Corporation's financial reporting.

33. Monitor and evaluate the Corporation's insurance programs.

34. Review with Management and the external auditor any off balance sheet arrangements and special purpose vehicle structures.

35. Review disclosure made to the Committee by the President and CEO, the CFO and the General Counsel of a violation of applicable securities laws, a breach of a fiduciary duty under applicable laws or a similar violation by the Corporation or by any officer, director, employee or agent of the Corporation, which has been reported to the Committee, and determine whether an investigation is necessary regarding any such violation and report to the Board.

36. Receive, review and consider the annual and interim certificates provided by the President and CEO and CFO of the Corporation pursuant to National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, as implemented by the Canadian Securities Administrators and as amended or replaced from time to time, along with reports from the Corporation's Disclosure Committee regarding the design and effectiveness of the Corporation's disclosure controls and internal controls over financial reporting.

37. Conduct all other matters required by law or stock exchange rules to be dealt with by an audit committee.

38. Review annually these terms of reference, the Ethics Policy, and the Corporation's policies regarding public disclosure of material information and insider trading (collectively, the "Disclosure Policy") and recommend any required material changes to the Corporate Governance, Compensation and Nominating Committee for further recommendation to the Board.

39. Conduct a regular, periodic survey relating to Committee effectiveness and performance.

40. Report to the Board as required.

D. MEETINGS

1. The Committee will meet at least quarterly and may call other meetings as required.

2. The minutes of the Committee meetings will accurately record the decisions reached and will be distributed to Committee Members, and, as directed by the Committee, to other Board members, the Senior Vice President and Chief Financial Officer (the "CFO") and others.

3. Committee meetings may be called by the Committee Chair or by a majority of the Committee Members. In addition, the Committee Chair will call a meeting upon request of the external auditors. The Committee Chair will be a voting member and questions will be decided by a majority of votes.

4. Meetings may be called with 24 hours' notice, which may be waived, before or after the meeting, by Committee Members. Attendance at a meeting will be deemed to be waiver of notice of the meeting, except where the Committee member attends the meeting for the express purpose of objecting to the transaction of business on the grounds that the meeting has not been duly called. All Committee Members are entitled to receive notice of every meeting.

5. Meetings are chaired by the Committee Chair or in the Committee Chair's absence, by a member chosen by the Committee amongst themselves.

6. Agendas will be set by the Committee Chair with such assistance as the Committee Chair may request from the President and CEO, Senior Vice President, General Counsel and Corporate Secretary, CFO and auditors, and will be circulated with the materials for consideration at the meeting by the Committee Chair or the Corporate Secretary to all Committee Members and, if directed by the Committee Chair, to the Chair of the Board, the President and CEO, the Senior Vice President, General Counsel and Corporate Secretary and the Senior Vice President and CFO, no later than the day prior to the date of the meeting. However, it should be standard practice to deliver the agenda and draft materials for consideration at the meeting at least five business days prior to the proposed meeting except in unusual circumstances.

7. Except as provided in these terms of reference, the Chair of the meeting may establish rules of procedure to be followed at meetings.

8. Meetings may be conducted with the participation of a member by telephone which permits all persons participating in the meeting to hear or communicate with each other. A member participating in a meeting by that means is deemed to be present at the meeting.

9. The powers of the Committee may be exercised by vote at a meeting at which a majority of the Committee Members are present or by a resolution in writing signed by all Committee

Members who would have been entitled to vote on the resolution at a meeting of the Committee. In the case of an equality of votes, the person acting as Chair of the Committee meeting will not be entitled to a second or casting vote.

10. A resolution in writing may be signed and executed in separate counterparts by Committee Members and the signing or execution of a counterpart will have the same effect as the signing or execution of the original. An executed copy of a resolution in writing or counterpart thereof transmitted by any means of recorded electronic transmission will be valid and sufficient.

11. Attendance at all or a portion of Committee meetings by staff, other directors, the auditors and others will be determined by the Committee.

12. The Corporate Secretary, or such other person as may be designated by the Committee, will keep minutes of the proceedings of all meetings of the Committee, which following Committee approval, will, subject to determination by the Committee otherwise, be available to any member of the Board. All minutes will be circulated to the Chair of the Board. With the exception of "in camera" items, minutes will be circulated to those receiving the agenda. Minutes will be retained by the Corporate Secretary.

13. The Committee may delegate its power and authority to individual Committee Members, where the Committee determines it is appropriate to do so in order for necessary decisions to be made between meetings of the Committee and where such delegation is permitted by law. Any such decisions will be reported to the Committee at its next meeting.