Annual Information Form

Capital Power Corporation

For the year ended December 31, 2021

February 24, 2022

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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, 2021. 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, adjusted funds from operations (AFFO) and normalized earnings attributable to common shareholders, as well as the non-GAAP ratios, AFFO per share and normalized earnings per share, 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 Integrated Annual Report dated February 23, 2022 for the year ended December 31, 2021.

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 "Non-GAAP Financial Measures and Ratios" and "Risks and Risk Management" sections on pages 60, and 86 of the Company's Integrated Annual Report dated February 23, 2022 for the year ended December 31, 2021 are 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, potential investors and other stakeholders 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 suggesting 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 AFFO; (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 and other environmental regulations on Capital Power's power facilities, including compliance costs and the useful lives of power facilities 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 new power market or energy resource regulations, 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 governing the operation of the dividend reinvestment plan for holders of Common Shares; (xiv) expectations for Capital Power's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings; (xv) expectations regarding power requirements and demand in Capital Power's target markets; (xvi) expectations around matters related to the line loss rule proceedings recovery of payments from appropriate parties and potential impacts to the Company arising from the foregoing; (xvii) the resolution of the pricing dispute of the Buckthorn Wind offtake and commodity swaps; (xviii) expectations regarding Capital Power's intention to acquire Common Shares pursuant to its normal course issuer bid; (xix) the timing, expected capital costs, project returns (including expected AFFO per share) and environmental benefits (including the expected reduction in emission levels) of gas conversion and repowering at the Genesee units (including Genesee units 1 and 2 being hydrogen-ready, and being off-coal in 2023); (xx) statements relating to our growth and sustainability strategy and sustainability targets, including reduction of emissions and emissions intensity and being net carbon neutral by 2050, completion of the Genesee Carbon Conversion Centre and commercial application of carbon conversion technologies; and (xxi) the impact of climate change and the COVID-19 pandemic.

These statements are based on certain assumptions and analyses made by the Company considering its experience and perception of historical and future trends, current conditions and expected future developments, and other factors it believes are appropriate, including its review of purchased businesses and assets. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity, other energy and carbon prices, (ii) performance, (iii) business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, (vi) the development and performance of technology, (vii) foreign exchange rates; (viii) matters relating to the line loss rule proceeding before the Alberta Utilities Commission, including the recovery of payments and timing thereof from appropriate parties; and other matters discussed under the “Our Strategy” section in the Company’s Integrated Annual Report dated February 23, 2022 pertaining to Performance Targets for 2022.

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) changes in electricity, natural gas and carbon prices in markets in which the Company operates and the use of derivatives, (ii) regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation, (iii) disruptions, or price volatility within the Company's supply chains, (iv) generation facility availability, wind capacity factor and performance including maintenance expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, (viii) ability to realize the anticipated benefits of acquisitions, (ix) limitations inherent in the Company's review of acquired assets, (x) changes in general economic and competitive conditions, (xi) changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs, and (xii) the risks and uncertainties discussed under the heading "Risks and Risk Management" in the Company's Integrated Annual Report dated February 23, 2022 for the year ended December 31, 2021.

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 – Western Canada Contracted Facilities – 150 Mile House"

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

"**AEP**" means Alberta Environment and Parks

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

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

"**AFFO**" means adjusted funds from operations

"**Affordable Clean Energy Rule**" means the Affordable Clean Energy Rule issued by the United States Environmental Protection Agency

"**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 Facilities – Arlington Valley"

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

"**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

"**Bear Branch Solar**" means the Bear Branch solar project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Bear Branch Solar"

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

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

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

"**Buckthorn Wind**" means the Buckthorn wind facility as further described in "Business of Capital Power – US Contracted Facilities – Buckthorn"

"**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

"**CNTs**" means carbon nanotubes

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

"**Capital Power**", "**CPC**" or the "**Company**" 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 facility as further described in "Business of Capital Power – US Contracted Facilities – 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

"**Clean Air Act**" means the Clean Air Act of 1963 (42 U.S.C. § 7401)

"**Clean Power Plan**" means the Clean Power Plan issued by the United States Environmental Protection Agency to regulate CO_2 for existing power facilities under the Clean Air Act

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

"**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"

"**CTG NOx Policy**" means the NO_x emission policy for CTG Units

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

"**DBRS**" means DBRS Limited

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

"**DRIP**" means dividend reinvestment plan

"**DSW**" means the Desert Southwest Region of the Western Area Power Administration

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

"**Enbridge**" means Enbridge Inc. collectively with its subsidiaries

"**Enchant Solar**" means the Enchant solar project as further described in "Company History – 2020 – Enchant Solar project proceeding"

"**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

"**EPS**" mean emissions performance standards

"**ERCOT”** means the Electric Reliability Council of Texas

"**ESG**" means environmental, social and governance

"**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 Canadian generally accepted accounting principles

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

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

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

"**Genesee 4 and 5**" means the Genesee 4 and 5 facilities that have been discontinued as described in "Company History – 2020 – Discontinuation of Genesee 4 and 5"

"**GGPPA**" means the *Greenhouse Gas Pollution Pricing Act* (S.C. 2018, c. 12, s. 186)

"**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

"**Goreway**" means the Goreway facility as further described in "Business of Capital Power – Ontario Contracted Facilities – Goreway"

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

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

"**Halkirk 1**" means phase 1 of the Halkirk wind project as further described in "Business of Capital Power – Alberta Commercial Facilities – Halkirk 1"

"**Halkirk 2**" means phase 2 of the Halkirk wind project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Halkirk 2"

"**Heartland Generation**" means Heartland Generation Ltd.

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

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

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

"**Hunter's Cove Solar**" means the Hunter's Cove solar project as further described in "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Hunter's Cove Solar"

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

"**Integrated Annual Report**" means the Company's Integrated Annual Report dated February 23, 2022

"**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

"**Island Generation**" means the Island Generation facility as further described in "Business of Capital Power – Western Canada Contracted Facilities – 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 Facilities – Joffre"

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

"**Keephills 3**" means the Keephills 3 coal-fired generating facility located 70 km west of Edmonton, Alberta

"**Lehigh**" means Lehigh Hanson, Inc.

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

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

"**MISO**" means Midcontinent Independent System Operator

"**Mitsubishi**" means Mitsubishi Power, Ltd.

"MSSC" means Most Severe Single Contingency

"**Moody's**" means Moody's Investors Service, Inc.

"**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 – US Contracted Facilities – 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"

"**NGCC**" means natural gas combined cycle

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

"**NO_x**" means oxides of nitrogen

"**NOVA**" means Nova Chemicals Corporation

"**OBPS**" means output-based pricing system

"**PCG**" means the People, Culture, and Governance Committee of the Company (formerly Corporate Governance, Compensation and Nominating Committee)

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

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

"**PJM**" means Pennsylvania, New Jersey and Maryland

"**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, Series 9 Shares and Series 11 Shares that are issued and outstanding

"**PSD**" means Prevention of Significant Deterioration

"**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 – Western Canada Contracted Facilities – 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 and 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) 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 Facilities"

"**Savona**" means the Savona waste heat facility as further described in "Business of Capital Power – Western Canada Contracted Facilities – 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.

"**SERC**" means the southeast electricity market that includes all or parts of Florida, Georgia, Alabama, Mississippi, North Carolina, South Carolina, Missouri and Tennessee.

"**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

"**Series 11 Shares**" means the cumulative minimum rate reset preference shares, series 11 issued by the Company

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

"**SO_2**" means sulphur dioxide

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

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

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

"**TIER**" means the *Technology Innovation and Emissions Reduction Regulation*, A.R. 133/2019

"**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 Wind**" means phases 1, 2 and 3 of the Whitla wind facility as further described in "Business of Capital Power – Western Canada Contracted Facilities – Whitla Wind"

"**York**" means the York Energy Centre as further described in "Business of Capital Power – Ontario Contracted Facilities – 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, July 31, 2017 and May 9, 2019 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 "Inter-Corporate Relationships" below.

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, 2021, 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 (Genesee) L.P.	Alberta
Decatur Energy Center, LLC	Delaware
Halkirk I Wind Project LP	Alberta
Capital Power (G3) Limited Partnership	Alberta
CP Bloom Wind LLC	Delaware
Arlington Valley, LLC	Delaware
Goreway Station Partnership	Ontario
Capital Power (Whitla) L.P.	Alberta
Cardinal Point LLC	Delaware
CP Energy Marketing (US) Inc.	Delaware

Notes:

(1) The Company indirectly owns 100% of the Class B Units of CP Bloom Wind LLC. The Class A Units of Bloom Wind LLC are held by the tax equity investor.

(2) The Company indirectly owns 100% of the Class B Units of Cardinal Point LLC. The Class A Units of Cardinal Point LLC are held by tax equity investors.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Capital Power is a growth-oriented North American independent power producer with a strategic focus on sustainable energy 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 several 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 facilities are discussed in greater detail under the heading "Business of Capital Power".

Company History

2021

6-year tolling agreement extension for Arlington Valley

On December 31, 2021, Capital Power executed a 6-year tolling agreement extension through October 2031 for its Arlington Valley facility with the current counterparty.

Arlington Valley currently sells capacity and electricity to an investment grade load serving utility (credit ratings of A3/BBB+ 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 produces power to support a heat rate call option (HRCO) with another investment grade counterparty when called upon. When not called to support the HRCO, Arlington Valley may sell energy into the DSW or the CAISO wholesale markets. Under the extension, the tolling agreement will cover six months of the year starting in 2026 compared to the four summer months currently.

When Capital Power announced the acquisition of Arlington Valley in 2018, the Company provided a forecasted average adjusted EBITDA of US$35 million per year (ranging from US$32 million to US$38 million) and US$16 million of AFFO during the 6-year period from 2020 to 2025. Under the terms of the tolling agreement extension, adjusted EBITDA will move towards the low end of the original guidance range for 2024 and 2025 before increasing to an average of US$47 million (ranging from US$42 million to US$49 million) per year and US$34 million of AFFO per year for the 6-year period from 2026 to 2031.

See also "Company History – 2019 – Heat Rate Call Option at Arlington Valley" and "Business of Capital Power – US Contracted Facilities – Arlington Valley".

Completion of phases 2 and 3 of Whitla Wind and Execution of 15-year contract

On December 1, 2021, an additional 151 MW from Whitla Wind, located in the County of Forty Mile, Alberta, began commercial operations following the completion of phases 2 and 3 of the project. At a total capital cost of $252 million, phases 2 and 3 of Whitla Wind were completed ahead of schedule and under-budget. In September 2021, Capital Power announced a 15-year renewable power purchase agreement with Dow Chemical Canada ULC, a subsidiary of Dow, for 25 MW of capacity and the associated environmental attributes from phases 2 and 3 of Whitla Wind. The Company continues to be in active discussions with commercial and industrial customers for renewable offtake contracts for the uncontracted generation from phases 2 and 3 of Whitla Wind.

See also "Company History – 2019 – Phase 2 of Whitla Wind project" and "Business of Capital Power – Western Canada Contracted Facilities – Whitla Wind".

Phase 2 of the Halkirk wind project proceeding

On December 2, 2021, Capital Power announced that, subject to successful permitting and regulatory approvals, it is moving forward with phase 2 of the Halkirk wind project located in the County of Paintearth, Alberta. The capital cost for the 151 MW phase 2 is expected to be approximately $274 million.

Phase 2 of the Halkirk wind project was fully permitted in 2018 based on available technology at that time. Since then, the project has been redesigned to incorporate the most advanced turbine technology, requiring a permit amendment. An amended AUC permit is anticipated to be issued late in the third quarter of 2023, allowing construction to start shortly thereafter with commercial operations targeted in the fourth quarter of 2024. The Company will leverage its strong local development advantage in Alberta, specifically in the Halkirk region to complete phase 2 of the project.

Phase 2 of the Halkirk wind project is expected to generate $32 million in adjusted EBITDA and $27 million in AFFO per year on average in the first 5 years of operation.

See also "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Halkirk 2".

Addition of battery storage to the Genesee 1 and 2 repowering project

On December 2, 2021, Capital Power announced that it has finalized its configuration for the Genesee 1 and 2 repowering project, adding up to 210 MW of battery storage. Subject to regulatory approvals, the addition of battery storage will address the Alberta Interconnected Electric System most severe single contingency limit, allowing the repowered Genesee 1 and 2 units to operate up to their baseload capacity. The revised repowering project cost is approximately $1.2 billion, including $195 million for battery storage.

Collaboration with Enbridge to reduce CO_2 emissions in Alberta

In a November 29, 2021, joint press release, Capital Power and Enbridge Inc. announced a memorandum of understanding to collaborate on CCS solutions in the Wabamun area west of Edmonton, near Capital Power's Genesee Generating Station.

Enbridge and Capital Power have agreed to collaborate on CCS initiatives (the Genesee CCS Project), with Enbridge as the transportation and storage service provider and Capital Power as the CO_2 provider, subject to the Government of Alberta's competitive carbon hub selection process and a future final investment decision. Enbridge, with the support of Capital Power, is applying to develop an open access carbon hub in the Wabamun area through the Government of Alberta's Request for Full Project Proposals process.

The proposed project would serve Capital Power's Genesee Generating Station, which currently provides over 1,200 MW of baseload electricity generation to Albertans. Capital Power is repowering the Genesee 1 and 2 units to create North America's most efficient natural gas combined cycle power generation units, positioning them to deliver reliable and affordable electricity for generations to come. The Genesee CCS Project is expected to capture up to 3 million tonnes of CO_2 annually from the repowered units, which would be transported and stored through Enbridge's open access carbon hub, that could also serve several other local industrial companies. Subject to the final award of carbon sequestration rights and regulatory approvals, the proposed project could be in service as early as 2026.

In October 2021, with Capital Power's support, Enbridge responded to the Government of Alberta's call for Expressions of Interest to construct and operate carbon storage hubs. Within its proposal, Enbridge outlined its plans to develop an open access carbon storage hub with cost-effective, customer-focused CCS solutions in the Wabamun area while minimizing any infrastructure footprint to protect land, water and the environment.

Acquisition of solar development sites in the United States

On November 24, 2021, Capital Power signed a Membership Interest Purchase and Sale Agreement to acquire 100% of a portfolio of 20 solar development sites (portfolio) in the United States from BW Solar Holding Inc., a U.S. solar and energy storage developer. Following satisfaction of customary conditions, the acquisition was completed in December 2021. The acquisition provides Capital Power with an attractive solar and storage platform for continued growth in the rapidly growing United States solar market.

The portfolio has a total generation capacity of 1,298 MW ranging in size from 15 MW to 340 MW, with the potential to co-locate over 1,200 megawatt hours of energy storage. The majority of the projects are in the MISO, PJM, and SERC electricity markets and are already in the interconnection queue in the respective regional transmission organization. The portfolio has attractive development and construction characteristics, and it is anticipated that sites will be construction-ready by 2024 with commercial operation dates in the 2025 to 2026 timeframe.

Suspension of Dividend Reinvestment Plan

On October 26, 2021, Capital Power announced that effective with the December 31, 2021 dividend, its DRIP for its common shares would be suspended. Shareholders participating in the DRIP began receiving cash dividends on the January 31, 2022 payment date.

See also "Common and Preferred Dividends – Dividend Reinvestment Plan".

Forced outage at Genesee 2

In July 2021, Genesee 2 experienced a forced outage due to a generator failure which is covered by the Company's insurance policy for both asset damage and business interruption. The unit was repaired and returned to service in early December 2021. Total Genesee 2 forced outage insurance recoveries of $46 million were recorded in 2021, including: (i) $ 35 million for asset damage, reflective of both the expensed and capitalized costs incurred to repair Genesee 2 (net of the deductible amount under the insurance contract) and (ii) $11 million in business interruption insurance recoveries. Total expenses recognized in relation to the outage were $12 million, including $6 million of damaged equipment written off, and total sustaining capital expenditures were $31 million. At December 31, 2021, $21 million of the insurance recoveries have been received.

Sustainability-linked credit facilities

On July 14, 2021, the Company announced the extension, amendment and transition of its existing committed credit facilities to sustainability-linked credit facilities (SLCs). The 5-year commitment to SLCs extends the Company's existing $1 billion of unsecured credit facilities, which include a $700 million syndicated credit facility and an unsecured club credit facility of $300 million, to July 2026. The SLCs are structured with one key performance indicator with annual sustainability performance targets aligned to one of Capital Power's publicly stated sustainability targets: to reduce Scope 1 CO_2 emission intensity by 65% by 2030 from 2005 levels. The SLCs include terms that reduce or increase borrowing costs as the annual targets are met or missed.

See also "Capital Structure – Credit Facilities".

Executive appointments

On April 30, 2021, Capital Power and the Board of Directors announced the following executive position appointments effective June 1, 2021:

- Bryan DeNeve, Senior Vice President Operations;
- Chris Kopecky, Senior Vice President and Chief Legal, Development and Commercial Officer; and

- Steve Owens, Senior Vice President Construction and Engineering.

Kate Chisholm, Sandra Haskins and Jacquie Pylypiuk continue to serve in their existing roles. Darcy Trufyn, Senior Vice President, Operations, Engineering and Construction retired from his role effective June 30, 2021.

Executed 15-year contract for Enchant Solar

On April 19, 2021, the Company announced that it executed a 15-year renewable energy agreement to sell 51% of the electricity generated from the 75 megawatt Enchant Solar project in Alberta to Labatt Brewing Company Ltd. of Canada, along with bundled renewable energy certificates (RECs). Of the contracted capacity under this agreement, approximately one-quarter will be bundled with project-generated RECs directly from Enchant Solar and three-quarters will be packaged with RECs sourced from Eastern Canada. The terms of this agreement are consistent with the previously disclosed financial expectations for Enchant Solar. The Company is also actively pursuing other contracting opportunities.

Construction of Enchant Solar commenced in the third quarter of 2021 with commercial operations expected in the fourth quarter of 2022.

See also "Business of Capital Power – Projects Under Construction in Advanced Stages of Development – Enchant Solar" and "Company History – 2021 – Enchant Solar proceeding".

United States power operations relating to extreme weather event

During the February 9 to 20, 2021 period, extreme winter weather caused some disruptions to our wind facilities, most notably in Kansas (Bloom Wind) and Texas (Buckthorn Wind) with no significant impact on the balance of Capital Power's U.S. operations. Buckthorn Wind and Bloom Wind experienced no significant physical damage, but some turbines were temporarily forced offline. Around this time, Buckthorn Wind became aware that the counterparty for its offtake and hedge agreements had been calculating the invoices for those agreements based on an incorrect reference price, which diverged widely from the reference price in the contracts during the period of extreme weather. The two parties are currently engaged in a dispute in the U.S. District Court for the Northern District of Texas over the correct reference price. Unfavorable resolution of the dispute would result in a net exposure to the Company's revenues of approximately $19 million (US$15 million).

Chair of the Board Transition

In February 2021, the Company announced that upon reaching his term limit after 12 successful years as Chair of the Board, Donald Lowry would retire from the Board at the 2021 annual general meeting (AGM). The Company also announced that the Board had appointed Jill Gardiner as successor Chair, effective immediately following the 2021 AGM.

<u>2020</u>

Expiry of Genesee 1 and 2 PPA

Until December, 31, 2020, Genesee 1 and 2 were subject to a PPA with the Balancing Pool. Under the terms of the PPA, the Balancing Pool was entitled to the power produced by Genesee 1 and 2, up to their committed capacity (381 MW for each unit). Generation in excess of committed capacity was managed as part of Capital Power's Alberta electricity portfolio optimization activities. Upon expiry of the PPA on December 31, 2020, both units became part of the Company's Alberta commercial facilities portfolio and are managed as part of Capital Power's Alberta electricity portfolio optimization activities. See "Business of Capital Power – Portfolio Optimization".

Acceleration of plans to repower Genesee

On December 3, 2020, Capital Power announced an update to the execution of its growth and sustainability strategy involving the repowering of Genesee 1 and 2 and being off-coal in 2023.

Capital Power is proceeding with its plans to repower Genesee 1 and 2, located west of Edmonton near Warburg, Alberta. A summary of the Company's plans for the project are as follows:

- Expected capital cost of $997 million with project returns expected to exceed the Company's hurdle rates and contributing approximately $0.70 in AFFO per share on average in the first five full years.
- Provides an additional 538 MW of net capacity totaling 1,338 MW.
- Simple cycle units will be completed first, allowing the units to run in simple cycle mode before the expected completion of the combined cycle mode of unit 1 in 2023 and unit 2 in 2024, avoiding any material downtime.
- Utilizing best-in-class air cooled J-series NGCC technology from Mitsubishi.
- 30% hydrogen-ready when repowering completed and upgradable to 95% in the future at minimal cost.
- Carbon conversion ready.
- Dual-fuel upgrades will only continue at Genesee 3, which will be 100% natural gas-fueled by 2023.
- Reduces the carbon intensity of Genesee 1 and 2 to 0.35 tonnes CO_2e/MWh, below the Alberta Technology Innovation and Emissions Reduction (TIER) regulation benchmark of 0.37 tonnes CO_2e/MWh.
- Following gas conversion and repowering, physical carbon dioxide emissions at the Genesee facility will be approximately 3.4 million tonnes per year lower than 2019 emission levels, with an additional estimated indirect 1 million-tonne annual reduction from displacement of less efficient units in the Alberta market.

See also "Company History – 2019 – Accelerated Plan for Genesee Natural Gas Capability", "Business of Capital Power – Alberta Commercial Facilities – Genesee 1 and 2", "Business of Capital Power – Alberta Commercial Facilities – Genesee 3" and "Company History – 2021 - Addition of battery storage to the Genesee 1 and 2 repowering project".

Enchant Solar proceeding

On December 3, 2020, Capital Power announced that, subject to successful permitting and regulatory approvals, it would be moving forward with the Enchant Solar project. This project is located within the municipal district of Taber, Alberta. The project will add 75 MW in the fourth quarter of 2022 at an expected capital cost of $119 million.

Enchant Solar will generate carbon credits that, where not sold to third parties, can be used to hedge against Capital Power's carbon compliance costs from its Alberta thermal generation facilities. Annual adjusted EBITDA and AFFO is expected to average approximately $11 million and $12 million, respectively, over the first five years of the project.

See also "Company History – 2021 – Executed 15-year contract for Enchant Solar project".

C2CNT and Genesee Carbon Conversion Centre

In December 2020, Capital Power exercised its option to increase its equity interest in C2CNT from 25% to 40% with the additional investment occurring during the first quarter of 2021. On November 1, 2021, Emission Reduction Alberta announced a commitment of $15 million in funding for the Genesee Carbon Conversion Centre through a contribution agreement. Capital Power continues to work towards the commercialization and design of the 2,500-tonne carbon nanotube facility. See also "Company History – 2019 – Capital Power Increases Interest in C2CNT" and "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

25-year PPA executed for Strathmore Solar project

In November 2020, Capital Power executed a 25-year PPA with TELUS Communications for all the energy and renewable energy credits generated by its Strathmore Solar project. Strathmore Solar is a 41 MW project located in Strathmore, Alberta. The Company started construction in the second quarter of 2021, with commercial operations expected to commence in March 2022.

See also "Company History – 2020 – Strathmore Solar Project" and "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Strathmore Solar".

20-year PPAs for three North Carolina solar development projects

On October 19, 2020, the Company announced the execution of 20-year PPAs with Duke Energy Carolinas for three solar development projects located in North Carolina totaling 160 MW. The solar projects consist of Hornet Solar (75 MW), Hunter's Cove Solar (50 MW), and Bear Branch Solar (35 MW) (collectively, the NC solar projects). Construction of the NC solar projects is expected to begin in early 2022, and commercial operations are expected to commence in the fourth quarter of 2024.

The initial build assumption includes $260 million (US$198 million) to construct the NC solar projects. The Company expects to finance the NC solar projects using debt and tax equity. The investment is expected to meet the Company's after-tax hurdle rate with the average accretion expected to be neutral to AFFO in the first five years. The solar projects are expected to generate approximately $23 million (US$17 million) of adjusted EBITDA and $5 million (US$4 million) of AFFO annually on average in the first five years.

See also "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Hornet Solar", "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Hunter's Cove Solar" and "Business of Capital Power – Projects Under Construction or Advanced Stages of Development – Bear Branch Solar".

10-year tolling agreement extension and CT upgrades for Decatur

On August 4, 2020, the Company executed a 10-year tolling agreement extension through December 2032 for Decatur with the current counterparty. On September 28, 2020, Decatur executed an amendatory interconnect agreement (the Amendatory Interconnect Agreement) that permits Decatur to transmit all capacity and energy to the current counterparty.

The tolling agreement extension and subsequent increases to the Interconnect Agreement allowed Decatur to invoice for 105MW of additional capacity as well as heat rate improvements. Relative to 2020 actual EBITDA, the increased capacity and heat rate improvements contribute to a, then expected, 2021 EBITDA increase of $10 million (US$8 million) and a 2022 EBITDA increase of $24 million (US$19 million). In 2023, the first year of the additional 10-year term, adjusted EBITDA is expected to be $69 million (US$54 million) per year and then decline by approximately 4% on average per annum over the term.

See also "Business of Capital Power – US Contracted Facilities – Decatur".

Strathmore Solar project

On July 30, 2020, the Company announced its plans to move forward with developing the Strathmore Solar project, the Company's first solar development project in Canada. Strathmore Solar is a 41 MW solar project, currently being constructed in Strathmore, Alberta. Construction began in the second quarter of 2021, and commercial operations are expected to commence in March 2022. All of the energy and renewable energy credits generated by the Strathmore Solar project will be sold under a 25-year PPA with TELUS Communications.

See also "Company History – 2020 – 25-year PPA executed for Strathmore Solar project" and "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Strathmore Solar".

Executive appointments

On July 30, 2020, Capital Power and the Board announced the following executive position appointments:

- B. Kathryn Chisholm, Senior Vice President, Planning, External Relations and Chief Sustainability Officer;
- Bryan DeNeve, Senior Vice President, Business Development and Commercial Services;
- Sandra Haskins, Senior Vice President, Finance and Chief Financial Officer;
- Chris Kopecky, Senior Vice President and Chief Legal Officer; and
- Jacquie Pylypiuk, Senior Vice President, People, Culture and Technology.

Darcy Trufyn continued to serve as the Senior Vice President, Operations, Engineering and Construction, but subsequently retired from his role effective June 30, 2021. Mark Zimmerman, who previously served as the Senior Vice President, Corporate Development and Commercial Services, stepped down from his role effective July 30, 2020.

Phase 3 of Whitla Wind project

On June 23, 2020, the Company announced that it was moving forward with developing the third phase of the Whitla Wind project, which added 54 MW in late 2021 and was combined with phase 2 for a total of 151 MW. The project started construction in Q3 2020, and reached commercial operation on December 1, 2021, with a total capital spend for the combined phases 2 and 3 of $252 million.

See also "Business of Capital Power – Western Canada Contracted Facilities – Whitla Wind" and "Company History – Completion of phases 2 and 3 of Whitla Wind and Execution of 15-year contract"

Wind facility long-term service agreement extensions and Whitla Wind phase 2 and 3 turbine supply

In late April 2020, the Company signed agreements with Vestas setting the terms for 10-year long-term service agreement (LTSA) extensions for the maintenance of nine of the Company's wind facilities and the supply of turbines for phases 2 and 3 of the Whitla Wind project.

The agreement for the 10-year extension on the series of LTSAs with Vestas covers a wider scope of services for all of our Vestas-equipped wind facilities while reducing costs by an estimated 26% compared to current service and maintenance agreements. The new LTSAs were executed in October 2020 and will take effect between 2021 and 2023. The Company expects to realize ongoing annual savings on the Company's wind facilities covered under these LTSAs, which would increase adjusted EBITDA and AFFO by approximately $8 million and $6 million per year, respectively. Additionally, the LTSA extensions include provisions intended to identify and encourage potential indigenous training, employment and economic opportunities at Canadian facilities.

Acquisition of Buckthorn Wind

On April 1, 2020, the Company acquired a 100% ownership interest in Buckthorn Wind from private investors. The purchase price consisted of (i) $84 million (US$60 million) in total cash consideration, including working capital and other closing adjustments, (ii) the assumption of tax-equity financing of $95 million (US$68 million) and (iii) contingent consideration valued at nil. Contingent consideration, to a maximum of US$8 million, would become payable in the future if certain market outcomes lead to Buckthorn Wind exceeding agreed upon thresholds. At the acquisition date, the Company considered the likelihood of contingent consideration payment to be low, resulting in no value being ascribed to the contingent consideration in the purchase price allocation. Buckthorn Wind has two hedge agreements with an investment grade U.S. financial institution, a 20-year (through early 2038) fixed-price contract for differences (CFD) for 55% of the project's as-generated energy output and RECs, and a 13-year (through early 2031) financial hedge for approximately 83% of the remaining 45% of the facility's energy output. Buckthorn Wind also has a tax equity investor that receives the tax benefits and a portion of adjusted EBITDA and cash flow until the flip-date that is projected to occur in the late 2020s. Prior to the flip-date, the Company expects average annual adjusted EBITDA and AFFO to be approximately $18 million (US$14 million) and $1 million (US$1 million), respectively. After the flip-date during the CFD, the average annual adjusted EBITDA and AFFO is expected to be approximately $9 million (US$8 million) and $6 million (US$5 million), respectively.

See also "Business of Capital Power – US Contracted Facilities – Buckthorn Wind".

Commercial operation and tax equity financing for Cardinal Point

On March 16, 2020, Cardinal Point began commercial operations and subsequently the Company received approximately US$157 million in net tax equity financing on March 26, 2020 from two U.S. financial institutions in exchange for Class A interests of a subsidiary of the Company. The Company operates Cardinal Point under a 12-year fixed-price financial hedge contract with an investment grade U.S. financial institution covering 85% of the facility's output.

See also "Business of Capital Power – US Contracted Facilities – Cardinal Point".

Discontinuation of Genesee 4 and 5

During the first quarter of 2020, the Company and its partner for the Genesee 4 and 5 project determined that they would no longer be pursuing the project. Arbitration commenced between the Company and its partner around the costs of exiting the series of previously entered into agreements, and the parties reached a settlement in the third quarter of 2021. As a result of the settlement, the Company reversed the provision initially recorded to gains on disposals and other transactions during the second quarter of 2021 and recognized an impairment loss of $8 million on the Company's consolidated statements of income related to assets acquired upon settlement. For the nine months ended September 30, 2021, the Company also recognized a pre-tax impairment reversal of $2 million related to the discontinuation of the Genesee 4 and 5 project for which the Company previously recognized a pre-tax impairment of $13 million during the nine months ended September 30, 2020.

Capital Power updates plans for President and Chief Executive Officer role

On February 24, 2020, the Company announced that Brian Vaasjo will remain as President and Chief Executive Officer of the Company for an additional three years. The February 24, 2020 announcement followed the Company's previous announcement on July 29, 2019 that Mr. Vaasjo had advised the Board of his intention to retire in 2020.

The July 29, 2019 announcement activated an established Chief Executive Officer succession plan developed by the Board. The Board's search for a new President and Chief Executive Officer was conducted through the remainder of 2019 and into early 2020, with the intention that the Board would announce a successor in due course. With the February 24, 2020 announcement that Mr. Vaasjo will continue as President and Chief Executive Officer for three more years, the Board's search for a replacement President and Chief Executive Officer ended.

2019

Genesee Carbon Conversion Centre

On December 5, 2019, the Company announced plans to build the Genesee Carbon Conversion Centre, the first-ever commercial scale production facility of CNTs at its Genesee facility, and to exercise options to increase its interest to 40% in C2CNT at the end of 2020.

Lehigh, a subsidiary of Heidelberg Cement A.G., a worldwide construction materials company, will be conducting testing for the utilization of CNTs in concrete. The Company plans to progress with construction and commercial scale production of CNTs at its Genesee facility, assuming the use of CNTs in concrete testing and preliminary marketing of the product is successful. The Genesee Carbon Conversion Centre could generate 2,500 tonnes of CNTs per year.

See also "Company History – 2020 – C2CNT and Genesee Carbon Conversion Centre".

Phase 2 of Whitla Wind project

On December 5, 2019, the Company announced that it would be moving forward with the second phase of the Whitla Wind project, which added 97 MW in 2021. The second and third phases of the Whitla Wind project were combined, for a total of 151 MW, and a total capital cost of $252 million. Phases 2 and 3 of Whitla Wind started construction in Q3, 2020 and reached commercial operation on December 1, 2021.

See also "Business of Capital Power – Western Canada Contracted Facilities – Whitla Wind" and "Company History – 2021 – Completion of phases 2 and 3 of Whitla Wind and Execution of 15-year contract".

Phase 1 of Whitla Wind Begins Commercial Operations

On December 1, 2019, phase 1 of Whitla Wind, located in the County of Forty Mile, Alberta, began commercial operations. Construction of the facility began in September 2018 and was completed on schedule and on budget within its $315 million to $325 million target, excluding foreign exchange impacts which were partially economically hedged. In December 2017, phase 1 of Whitla Wind was one of four successful wind projects that was awarded a 20-year contract by the AESO in the first round of the REP, which attracted global competition.

See also "Business of Capital Power – Western Canada Contracted Facilities – Whitla Wind".

Capital Power Assumes 100% Ownership and Control of Genesee 3 Generating Station

On August 2, 2019, the Company announced it had entered into an agreement to divest its 50% share of Keephills 3 to TransAlta, and to acquire TransAlta's 50% share of Genesee 3. The transaction closed on October 1, 2019, with a net cost to the Company of $10 million, subject to working capital and other closing adjustments. Previously both facilities had been owned and operated under 50/50 joint venture agreements between the Company and TransAlta. Following the close of the transaction, Genesee 3 is fully owned and operated by the Company and Keephills 3 is fully owned and operated by TransAlta.

Keephills 3 and Genesee 3 are the only supercritical coal facilities in Alberta, with a net capacity of 463 MW and 466 MW, respectively. The swap of interests in the facilities is aligned with the Company's strategic plan to deliver responsible energy for tomorrow. As a result of the transaction, the Company gained full control of the Genesee site, providing strategic freedom and latitude to make decisions that further optimize value for all three Genesee units.

See also "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

Accelerated Plan for Genesee Natural Gas Capability

During 2019, the Company announced that it would maximize the flexibility to utilize natural gas as fuel at Genesee, which previously burned primarily coal. The total cost of the project to completely transform the Genesee units to dual-fuel capability was estimated at $70 million with expenditures of $10 million incurred in 2019, $43 million incurred in 2020, $8.4 million in 2021 and a forecast of $4.7 million in 2022.The project involved adding new gas pipeline infrastructure within the Genesee site and modifications to the Genesee 1 and 2 boilers. The rated capacity of the units was to remain the same. The Company has since announced on December 3, 2020, that it will only be moving forward with dual fuel capability on Genesee 3 given the decision to repower units 1 and 2.

After Genesee 3 has been transformed to 100% dual-fuel capability, the unit can utilize up to 100% natural gas or coal, or a mix of the two. The amount of coal used at any given time, versus natural gas, will be driven by several factors including natural gas and coal prices and carbon costs. Once Genesee 1 and 2 are burning 100% natural gas under the repowering plan, mining of coal at the Genesee coal mine will be discontinued and Genesee 3 will burn 100% natural gas by 2023.

The Genesee units are already the most efficient coal generating units in Alberta and best performing from an emissions intensity perspective. Under the Genesee Performance Standard program, which commenced in 2016, a 12% improvement in efficiency and performance of the units is targeted by 2023, which improvements will benefit ongoing natural gas operations. See also "Business of Capital Power – Alberta Commercial Facilities – Genesee 1 and 2" and "Business of Capital Power – Alberta Commercial Facilities – Genesee 3".

Capital Power is repowering both units utilizing best in class NGCC technology, setting a new standard for gas generation efficiency in the province.

See also "Company History – 2020 – Acceleration of plans to repower Genesee". As a result of the repowering, Genesee will cease utilizing coal in 2023.

Acquisition of Goreway Power Station

On April 29, 2019, the Company announced that it had entered into an agreement to acquire Goreway Power Station Holdings Inc., which owned the Goreway Power Station (Goreway), an 875 MW natural gas combined cycle generation facility located in Brampton, Ontario.

On June 4, 2019, the Company completed the acquisition of 100% of the ownership interests in Goreway. The purchase price consisted of (i) $405 million of total cash consideration, including working capital and other closing adjustments of $18 million, and (ii) the assumption of $590 million of project level debt. Financing of the Goreway acquisition consisted of a combination of debt from the Company's existing credit facilities and equity offerings.

The Goreway facility has a 20-year Accelerated Clean Energy Supply Contract expiring in June, 2029 with the Ontario IESO. Goreway is strategically located in the Greater Toronto Area load centre making it an important asset in Ontario's electric system and, in combination with the Company's other Ontario natural gas assets, will provide operating and market synergies over time. The acquisition of Goreway supports the Company's growth strategy and fully meets the Company's investment criteria.

See also "Business of Capital Power – Ontario Contracted Facilities – Goreway".

Capital Power Increases its Equity Interest in C2CNT

In May 2019, the Company committed to increase its equity interest in C2CNT from 5% to 9% by March of 2020 and in August 2020, further increased its equity interest from 16% to 25%.

The Company had the right to provide notice to exercise a final option before the end of 2020 for an additional 15% equity interest in C2CNT. In December 2020, Capital Power exercised its option to increase its equity interest in C2CNT from 25% to 40% with the additional investment occurring during the first quarter of 2021. See also "Company History – 2020 – C2CNT and Genesee Carbon Conversion Centre".

The investment supports the Company's pursuit of innovative and leading-edge technology to reduce greenhouse gases.

Lehigh agreed to conduct testing for the utilization of CNTs in concrete at their cost. Lehigh also made a modest financial contribution to C2CNT development.

Heat Rate Call Option at Arlington Valley

During the first quarter of 2019, the Company entered into a heat rate call option agreement (HRCO) with an investment grade counterparty covering the periods outside of Arlington Valley's existing summer tolling agreements. The HRCO commenced on April 1, 2019 and terminates December 31, 2025, covering (i) April and November-December 2019 and (ii) January-May and October-December 2020-2025. Pursuant to the HRCO the counterparty has the right to call power in exchange for fixed monthly premiums plus reimbursements for fuel at an indexed price, variable operating and maintenance expense and start charges.

See also "Business of Capital Power – US Contracted Facilities – Arlington Valley" and "Company History – 2022 - 6-year tolling agreement extension for Arlington Valley".

BUSINESS OF CAPITAL POWER

Overview

Capital Power is a growth-oriented North American wholesale power producer with a strategic focus on sustainable energy headquartered in Edmonton, Alberta. We build, own and operate high-quality, utility-scale generation facilities that include renewables such as wind, solar and waste heat, and thermal such as natural gas and coal. We have also made significant investments in carbon capture and utilization to reduce carbon impacts and are committed to be off coal in 2023.

Capital Power owns approximately 6,600 megawatts (MW) of gross power generation capacity at 26 facilities across North America. Projects in advanced development include approximately 425 MW of owned renewable generation capacity in North Carolina and Alberta and 512[1] MW of incremental natural gas combined cycle capacity, from the repowering of Genesee 1 and 2 in Alberta, as well as up to 210 MW of battery storage.

As of December 31, 2021, Capital Power's power generation fleet had a capacity weighted average facility age of 15 years and is diversified across three Canadian provinces and eight states in the US.

Capital Power owns nearly 2,800 MW of power generation capacity in Alberta, with ownership interests in nine facilities. As of January 1, 2022, the majority of power generated by the Alberta generation facilities in which the Company owns an interest, is sold on a merchant, or non-contracted, basis as part of Capital Power's portfolio optimization activities. See "Business of Capital Power – Portfolio Optimization" and Company History – 2020 – Expiry of Genesee 1 and 2 PPA".

Capital Power sells some of the power generated by its Alberta power facilities and majority of the power generated by its power facilities outside of Alberta, on a contracted basis to arm's length third parties. See "Business of Capital Power – Western Canada Contracted Facilities", "Business of Capital Power – Ontario Contracted Facilities" and "Business of Capital Power – US Contracted Facilities".

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1 Following the repowering of Genesee 1 and 2, load for the facility will decrease from 60 MW to 34 MW resulting in a 538 MW increase in net capacity for the repowered facility.

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. Capital Power's corporate purpose is to power a sustainable future for people and planet, so our decisions include consideration for Environmental, Social and Governance (ESG) factors, which help drive innovation and better decisions in the interests of our many different stakeholders.

Capital Power's sustainability targets, including ambitious carbon emissions-reduction targets, reflect our commitment to being an investment, employer, supplier and neighbour of choice. These targets, detailed below, include an ambitious target to be net carbon neutral before 2050.

- Achieve net carbon neutrality before 2050
- Construct all new natural gas generation units to be carbon capture and/or hydrogen-ready
- Reduce Scope 1 CO_2 emissions at Genesee by 50% by 2030 from 2005 levels
- Reduce Scope 1 CO_2 emissions by 10% by 2030 from 2005 levels, based on our 2019 fleet
- Reduce Scope 1 CO_2 emission intensity by 65% by 2030 from 2005 levels
- Invest in carbon capture and utilization technology to help achieve net carbon neutrality by 2050 and eventually physically decarbonize our natural gas fleet (ongoing)
- Complete the Genesee Carbon Conversion Centre

In addition to the targets noted above, in 2022 Capital Power increased and expanded the link between incentive pay and the successful delivery of our ESG objectives. In 2022, 25% of executive short-term compensation and 15% of non-executive short-term incentive pay will be based on the fulfillment of ESG objectives, and 20% of 2022 executive and leadership performance share units will include ESG elements. This expands on our previous ESG-related metrics in compensation and ensures that delivering on our objectives is the responsibility of all individuals in leadership at Capital Power. This approach directly links sustainability to our corporate strategy and ensures we are delivering long-term value to all stakeholders.

Generation Facility Summary

The following table provides details of Capital Power's generation facilities that are in service, under construction or in advanced stages of development as at December 31, 2021:

Category	Facility Name and Location	Type of Generating Facility	Year Commissioned or Target Date	Facility Generation Capacity (MW)[1]	Capital Power Interest (MW)[1]
Alberta Commercial Facilities	Genesee 3, Alberta	Supercritical coal and natural gas co-fired	2005	516	516
	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	243	243
	Clover Bar Landfill, Alberta	Land fill gas-fired	2005	2	2
	Halkirk 1, Alberta	Wind turbine	2012	150	150
	Shepard, Alberta	Natural gas-fired, combined cycle	2015	881	440

Category	Facility Name and Location	Type of Generating Facility	Year Commissioned or Target Date	Facility Generation Capacity (MW)(1)	Capital Power Interest (MW)(1)
	Genesee 1 and 2, Alberta(5)	Coal and natural gas co-fired	Genesee 1 -1994 Genesee 2 -1989	430 430	430 430
	Total Alberta Commercial Facilities (2) (3)				**2,403**
Ontario Contracted Facilities					
	Kingsbridge 1, Ontario	Wind turbine	2001 & 2006	40	40
	York, Ontario	Natural gas	2012	456	228
	PDN, Ontario	Wind turbine	2013	105	105
	Goreway, Ontario	Natural gas	2009	875	875
	East Windsor, Ontario	Natural gas	2009	92	92
	Total Ontario Contracted Facilities(2)				**1,340**
Western Canada Contracted Facilities	Whitla Wind, Alberta(3)(7)	Wind turbine	Phase 1 – 2019 Phases 2&3 - 2021	202 151	202 151
	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
	Quality, BC	Wind turbine	2012	142	142
	Total Western Canada Contracted Facilities(2)				**780**
US Contracted Facilities					
	Arlington Valley, Arizona	Natural gas	2002	600	600
	Decatur, Alabama	Natural gas	2002	885	885
	Macho Springs, New Mexico	Wind turbine	2011	50	50
	Beaufort, North Carolina	Solar	2015	15	15
	Bloom, Kansas	Wind turbine	2017	178	178
	Buckthorn Wind, Texas	Wind turbine	2018	101	101
	New Frontier, North Dakota	Wind turbine	2018	99	99
	Cardinal Point, Illinois	Wind turbine	2020	150	150
	Total US Contracted Facilities(2)				**2,078**
Facilities Under Construction or in Advanced Stages of Development	Halkirk 2, Alberta	Wind turbine	2024	151	151
	Strathmore Solar, Alberta	Solar	2022	41	41
	Enchant Solar, Alberta	Solar	2022	75	75
	Bear Branch Solar, North Carolina	Solar	2024	35	35
	Hornet Solar, North Carolina	Solar	2024	75	75
	Hunter's Cove Solar, North Carolina	Solar	2024	50	50

Category	Facility Name and Location	Type of Generating Facility	Year Commissioned or Target Date	Facility Generation Capacity (MW)(1)	Capital Power Interest (MW)(1)
	Repowering of Genesee 1 and 2 with battery storage, Alberta	Natural gas	Genesee 1 - 2023 Genesee 2 - 2024 Battery Storage - 2024	256(6) 256(6) 210(6)(8)	256(6) 256(6) 210(6)(8)
	Total Under Construction or in Advanced Stages of Development				**939**
Total Capital Power(4)					**7,540**

Notes:

(1) MW listed are gross capacity.
(2) Represents Capital Power's owned capacity as at the date of this AIF.
(3) Based on the nature of future cash flows, the Alberta assets are combined as one cash-generating unit (CGU) for impairment testing purposes.
(4) Represents Capital Power's owned capacity, capacity under construction or in advanced stages of development as at the date of this AIF.
(5) The power purchase arrangement for Genesee 1 and 2 expired on December 31, 2020. Commencing in 2021, these facilities are now reported within the Alberta commercial facilities grouping.
(6) Represents additional capacity to be developed at the Genesee 1 and 2 facilities.
(7) Whitla Wind consists of 3 phases. Phase 1 (202 MW) is owned by Capital Power (Whitla) L.P. and phases 2 and 3 (151 MW) are owned by Whitla 2 Wind Generation L.P. For contracting purposes, phases 2 and 3 are contracted together, while phase 1 is contracted separately. For operational reporting, the Company combines all phases of the Whitla Wind project as a single facility referred to as Whitla Wind.
(8) Battery storage is excluded from the total capacity as the current sole function anticipated for the battery is to support G1&2's MSSC constraint.

Revenue and Volume

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

	Revenues and other income (unaudited $ millions)	
Category	**Twelve Months Ended December 31, 2021**	**Twelve Months Ended December 31, 2020**
Alberta commercial facilities(1)	1,350	1,036
Western Canada contracted facilities(1), (2)	133	131
Ontario contracted facilities(2)	316	297
U.S. contracted facilities	402	463
Corporate	126	55
Sub Total	2,327	1,982
Unrealized changes in fair value of commodity derivatives and emission credits	(337)	(45)
Total	**1,990**	**1,937**

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, 2021**	**Twelve Months Ended December 31, 2020**
Alberta commercial facilities(1)	12,877	14,668
Western Canada contracted facilities(1), (2)	1,923	1,396
Ontario contracted facilities(2)	1,629	1,400
U.S. contracted facilities	6,382	6,342
Total	**22,811**	**23,806**

(1) The Genesee 1 and 2 Power Purchase Arrangement (PPA) expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative period reflect energy sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

(2) During the first quarter of 2021, management reviewed its facility groupings as a result of the change in classification of Genesee 1 and 2 as well as internal organizational changes. To best reflect how the Company operates, commencing January 1, 2021, the British Columbia and Alberta contracted facilities are now reported together as Western Canada contracted facilities with the Ontario contracted facilities in a separate grouping. Comparative figures have been reclassified to conform to the current period's presentation.

Alberta Commercial Facilities

As of December 31, 2021, the Alberta commercial facilities consisted of ownership interests in eight facilities representing approximately 2,403 MW of power generation capacity. The facilities generate electricity from coal, natural gas, wind and landfill gas. The output of the Alberta facilities is managed on a portfolio basis by Capital Power's Commodities team. Output from these facilities is sold into the deregulated Alberta power market. The PPA for Genesee 1 and 2 expired on December 31, 2020. Commencing in 2021, these facilities are now reported within the Alberta commercial facilities grouping.

Capital Power seeks to maximize earnings from the Alberta commercial facilities 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.

Genesee 1 and 2

Genesee 1 and 2, are coal-fired power facilities 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 and 2 were commissioned in 1994 and 1989, respectively.

Commercial Arrangement: Merchant Facility

Until December 31, 2020, Genesee 1 and 2 were subject to a PPA with the Balancing Pool. Upon expiry of the PPA on December 31, 2020, both units became part of the Company's Alberta commercial facilities portfolio and are managed as part of Capital Power's Alberta electricity portfolio optimization activities.

Fuel Supply

Coal required for the Genesee power facilities is supplied by the adjacent Genesee coal mine. The coal is provided to the Genesee power facilities under a 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.

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. Once Genesee 1 and 2 are burning 100% natural gas under the repowering plan, mining of coal at the Genesee coal mine will be discontinued, and Genesee 3 will burn 100% natural gas by 2023.

The Company intends that the Genesee 1 and 2 facilities will fully accommodate natural gas for fuel supply and will be off-coal by the end of 2023. See "Company History – 2020 – Acceleration of plans to repower Genesee". After the repowering of Genesee 1 and 2, natural gas for these facilities will be purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada currently provides firm and interruptible transport services to the site and a new pipeline was completed and commissioned in 2020 of sufficient size to handle all of the current Genesee natural gas needs. This new natural gas pipeline also holds significant expansion potential should the gas needs at Genesee materially increase with future development.

Genesee 3

Genesee 3 is a 516 MW supercritical coal power facility, that has 40% natural gas co-fire capabilities, located adjacent to Genesee 1 and 2 near Warburg, Alberta, which was commissioned in 2005. Genesee 3 is 100% owned and operated by Capital Power as of October 1, 2019. 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.

In the second quarter of 2022 Genesee 3 will undergo modifications to enable 100% dual fuel (coal and natural gas) capabilities. Once these modifications are complete, the asset will have the ability to burn either 100% coal, 100% natural gas, or some combination thereof until 2023 when Capital Power plans to be off coal.

Commercial Arrangement: Merchant Facility

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

Fuel Supply

Coal required for the Genesee power facilities is supplied by the adjacent Genesee coal mine. The coal is provided to the Genesee power facilities under a 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.

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. Once Genesee 1 and 2 are burning 100% natural gas under the repowering plan, mining of coal at the Genesee coal mine will be

discontinued and Genesee 3 will burn 100% natural gas by the end of 2023. See "Company History 2020 – Acceleration of plans to repower Genesee".

When natural gas is more economic than coal, natural gas for Genesee is purchased in the Alberta wholesale market to meet dispatch requirements. A natural gas transportation agreement with TransCanada provides firm and interruptible transport services to the site and a new pipeline was completed and commissioned in 2020 of sufficient size to handle all of the current Genesee natural gas needs. This new natural gas pipeline also holds significant expansion potential should the gas needs at Genesee materially increase with future development.

Joffre

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

The facility produces both steam and electricity for NOVA's host petrochemical complex. On average, 125 MW of the net electricity output of the cogeneration facility is required on site by the host petrochemical complex with the balance being sold to the wholesale electricity market. Heartland Generation operates the facility 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, as amended, among a subsidiary of Capital Power, Heartland Generation 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 facility is bid into the wholesale electricity market by Heartland Generation 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 facility 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 and permitted to meet the need for peaking, mid-merit and baseload capacity in Alberta.

Clover Bar unit #1 (LM6000) is scheduled for a hot gas path overhaul in Q1 of 2022 based on forecasted usage.

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 most of the capacity.

Halkirk 1

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

Commercial Arrangement: Merchant Facility for Energy (Power Purchase Agreement for RECs)

The electricity generated by Halkirk 1 is managed as part of Capital Power's Alberta electricity portfolio optimization activities. RECs produced by Halkirk 1 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. On June 20, 2020, the United States Bankruptcy Court for the Northern District of California, San Francisco Division, confirmed PG&E's plan of reorganization under Chapter 11 (the Plan) and the Plan became effective on July 1, 2020, at which point PG&E emerged from creditor protection. As part of the Plan, PG&E assumed all its obligations under the fixed-price agreement with Halkirk 1 and paid the pre-Chapter 11 petition debt it owed to Halkirk 1 in full on August 7, 2020. At this time, PG&E has continued to fulfill its obligations to Halkirk 1 under the fixed price agreement.

Shepard

Shepard is an 881 MW natural gas fired combined-cycle power facility 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.

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 2018 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 Facility, recently repowered under a life extension project to a 2 MW facility located in Edmonton, Alberta. The landfill gas collection system was commissioned in 1992 to provide gas to the process facility for cleaning and flaring and under the life extension work is expected to operate until 2023.

The facility creates carbon offset credits through both the flare and electrical generation under a renewed carbon offset program until Q3 of 2023. The environmental operating approval was renewed on March 31, 2021 and is valid to Q1 of 2031. Flaring and/or use of the landfill gas for power generation creates carbon offset credits through the collection and combustion of methane. Electrical output from the facility is sold into the Alberta wholesale electricity market at spot price.

Western Canada Contracted Facilities

Whitla Wind

Whitla Wind is a 353 MW wind facility located in the County of Forty Mile, Alberta that consists of 3 phases. Phase 1 began commercial operations on December 1, 2019 and is comprised of 56 Vestas V136 turbines, each with a generation capacity of 3.6 MW. Phases 2 and 3 reached commercial operation on December 1, 2021 and added 151 MW of generation capacity.

Commercial Arrangement: Renewable Energy Support Agreement (RESA) Swap Arrangement

In December 2017, phase 1 of Whitla Wind was awarded a 20-year contract by the AESO in the first round of the Renewable Electricity program which attracted global competition. The RESA contract is in effect a contract-for-differences covering phase 1 of Whitla Wind's entire output for 20 years, and additionally will provide the AESO with all the renewable attributes generated by phase 1 of the project.

On September 15, 2021, the Company executed a 15-year renewable power purchase agreement with Dow Chemical Canada ULC, a subsidiary of Dow, for 25 MW of capacity and the associated environmental attributes from phases 2 and 3 of Whitla Wind. The Company continues to be in active discussions with commercial and industrial customers for renewable offtake contracts for the uncontracted generation from phases 2 and 3 of Whitla Wind.

Island Generation

Island Generation is a 275 MW natural gas combined-cycle power facility 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. For discussion of the Company's efforts with respect to renewal of the tolling arrangement with BC Hydro, see also "Regulatory Overview – BC".

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 EPA with BC Hydro, with original terms expiring in 2028.

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 which expires in 2037.

<u>Ontario Contracted Facilities</u>

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.

East Windsor

East Windsor is a 92 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: Combined Heat and Power Contract

The facility is fully contracted with the Ontario IESO until 2029 and had a long-term steam agreement to supply FMCC's Windsor engine facility that terminated in May of 2020. In 2021 the company agreed with the IESO to operate the facility as a simple cycle generator with no steam host.

Fuel Supply

Capital Power procures and delivers the fuel for the facility. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas.

York

York is a 456 MW natural gas facility located northwest of Newmarket, Ontario in the Township of King. This facility is the largest quick-response gas-fired peaking facility 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. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas, most 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 2033.

Goreway

Goreway is an 875 MW natural gas combined cycle generation facility located strategically in Brampton, Ontario, within the Greater Toronto Area load centre. The Goreway facility utilizes best-in-class gas-fired generation equipment including three upgraded GE 7FB.04 combustion turbines, three Deltak heat recovery steam generators and a single Siemens steam turbine. The commercial operational date of the facility was June, 2009 and Capital Power acquired Goreway in June, 2019.

Commercial Arrangement: Accelerated Clean Energy Supply Contract

Goreway has a 20-year Accelerated Clean Energy Supply Contract expiring in June 2029 with the Ontario IESO.

Fuel Supply

Capital Power procures and delivers the fuel for the facility. Natural gas transportation contracts and natural gas storage contracts are in place to provide firm delivery of natural gas.

US Contracted Facilities

Roxboro

Roxboro was a 46 MW biomass power facility located in Roxboro, North Carolina, and was commissioned in 1987 and acquired by Capital Power in conjunction with the Capital Power Income L.P. divestiture in November 2011. Roxboro ceased operations after March 31, 2021 and is currently in the process of being decommissioned by D.H. Griffin, who is a large contractor with significant demolition, salvage, and reclamation experience of industrial sites. Decommissioning is expected to conclude mid-2022 and the Roxboro property to be transacted to a yet-to-be-identified new owner.

Commercial Arrangement: Power Purchase Agreement

Roxboro sold all 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 expired at the end of March 2021.

Commercial Arrangement: REC

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

Fuel Supply

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

Southport

Southport was an 88 MW biomass cogeneration heat and power facility located in Southport, North Carolina, and was commissioned in 1987 and acquired by Capital Power in November 2011. Southport ceased operations after March 31, 2021 and is currently in the process of being decommissioned by D.H. Griffin, who is a large contractor with significant demolition, salvage, and reclamation experience of industrial sites. Decommissioning is expected to conclude mid-2022 with the Southport property reverting back to Duke Energy Corporation as the landowner.

Commercial Arrangement: Power Purchase Agreement

Southport provided all 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 expired at the end of March 2021. Southport also sold steam to Archer Daniels Midland Company pursuant to a contract that expired at the end of March 2021.

Commercial Arrangement: REC

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

Fuel Supply

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

Decatur

Decatur is an 885 MW output natural gas-fired combined cycle power generation facility located in Decatur, Alabama, that Capital Power acquired on June 13, 2017. The facility is a 3X1 combined cycle facility comprised of three Siemens SGT6-5000F 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 leased 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 with an A-rated credit rating and is fully contracted until the end of 2032.

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 80% of the earnings, tax benefits, and cash flows. The reversion occurred on September 30, 2018.

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 in 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: Financial Proxy Revenue Swap Agreement

Capital Power owns and operates Bloom under a 10-year, fixed revenue contract with Allianz Risk Transfer, a subsidiary of Allianz SE, covering most of the facility's output (approximately 93%, based on actuals since commercial operations commenced). Under the contract, Capital Power swaps the market revenue of the facility's proxy generation for a fixed annual payment until April 2026. Surplus energy above the proxy volume is sold unhedged as merchant. 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 600 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 Agreement and Heat Rate Call Option

On January 4, 2022, Capital Power announced the execution of a 6-year tolling agreement extension through October 2031 for its Arlington Valley facility with the current counterparty.

Arlington Valley currently sells capacity and electricity to an investment grade load serving utility (credit ratings of A3/BBB+ 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 produces power to support a heat rate call option with another investment grade counterparty when called upon. When not called to support the heat rate call option, Arlington Valley may sell energy into the DSW or the CAISO wholesale markets. Under the extension, the tolling agreement will cover six months of the year starting in 2026 compared to the four summer months currently.

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 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: Financial Swap Agreement

Meadowlark Wind I LLC, the New Frontier project company, has entered into a financial hedge agreement with an investment grade U.S. financial institution that covers approximately 87% of the facility's output. The hedge is fixed-price for a fixed notional quantity of energy and settles at the MISO Minnesota Hub. The financial hedge has a twelve-year term that began on March 1, 2019. The remainder of the energy output is sold unhedged as merchant.

Buckthorn Wind

Buckthorn Wind is a 101 MW wind facility located approximately 60 miles southwest of Dallas in Erath County, Texas and comprised of 29 Vestas wind turbines. The facility began commercial operations in January 2018 and operates in the liquid ERCOT North region, which is situated between most of the wind generation in ERCOT-West and the Dallas load center

Commercial Arrangement: Contract for Differences (CFD)/REC off-take and Financial Swap Agreement

Buckthorn Wind has two financial hedges with an investment grade US financial institution, the first of which is a 20-year (through early 2038) fixed-price contract for differences for 55% of the project's as-generated energy output and RECs, the second of which is a 13-year (through early 2031) financial swap agreement for approximately 85% of the remaining 45% of energy output. Both financial hedges are fixed-price (the second hedge for a fixed notional quantity of energy) and settle at the ERCOT North Hub. Capital Power acquired Buckthorn Wind from private investors in April 2020.

Cardinal Point

Cardinal Point is a 150 MW facility located in the McDonough and Warren Counties, Illinois. Commercial operation of the facility began on March 16, 2020. In addition, the Company received approximately $221 million (US$157 million) in tax equity financing on March 26, 2020, net of issue costs of $3 million (US$2 million) associated with the financing, from two U.S. financial institutions in exchange for Class A interests of a subsidiary of the Company.

Commercial Arrangement: Financial Swap Agreement

Commencing January 1, 2021, Capital Power operates Cardinal Point under a 12-year financial swap agreement with an investment grade U.S. financial institution covering approximately 85% of the facility's output. The hedge is fixed-price for a fixed notional quantity of energy, and settles at the AMIL.BGS6 Load Zone. The remainder of the energy output is sold unhedged as merchant. In addition, the project has secured three 15-year, fixed-price REC contracts with three Illinois utilities for approximately 95% of the forecast RECs, with the balance marketed on a merchant basis. Prior to January 1, 2021 the energy output of Cardinal Point was unhedged.

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:

Halkirk 2

Subject to successful permitting and regulatory approvals, Capital Power is moving forward with phase 2 of the Halkirk wind project located in the County of Paintearth, Alberta. The capital cost for the 151 MW phase 2 is expected to be approximately $274 million.

Phase 2 of the Halkirk wind project was fully permitted in 2018 based on available technology at that time. Since then, the project has been redesigned to incorporate the most advanced turbine technology, requiring a permit amendment. An amended AUC permit is anticipated to be issued late in the third quarter of 2023, allowing construction to start shortly thereafter with commercial operations targeted in the fourth quarter of 2024.

Strathmore Solar

Strathmore Solar is a 41 MW solar project, currently under construction in Strathmore, Alberta. Construction began in the second quarter of 2021, with a commercial operation date expected in March 2022. All of the energy and renewable energy credits generated by its Strathmore Solar project will be sold under a 25-year PPA with TELUS Communications.

Enchant Solar

Enchant Solar is a fully permitted 75 MW solar project located within the municipal district of Taber, Alberta. Construction began in the fall of 2021 and is expected to reach commercial operations in the fourth quarter of 2022 at an expected capital cost of $119 million. The Company executed a 15-year renewable energy agreement to sell 51% of the electricity generated from Enchant Solar to Labatt Brewing Company Ltd. of Canada, along with bundled renewable energy certificates (RECs).

Bear Branch Solar

Bear Branch Solar is a proposed 35 MW solar project, located in Stokes County, North Carolina. Construction of the project is expected to begin in early 2022, with commercial operations expected in the fourth quarter of 2024. The Company will operate Bear Branch Solar under a 20-year power purchase agreement with Duke Energy Carolinas.

Hornet Solar

Hornet Solar is a proposed 75 MW solar project, located in Gaston and Lincoln Counties, North Carolina. Construction of the project is expected to begin in early 2022, with commercial operations expected in the fourth quarter of 2024. The Company will operate Hornet Solar under a 20-year power purchase agreement with Duke Energy Carolinas.

Hunter's Cove Solar

Hunter's Cove Solar is a proposed 50 MW solar project, located in Rutherford County, North Carolina. Construction of the project is expected to begin in early 2022, with commercial operations expected in the fourth quarter of 2024. The Company will operate Hunter's Cove Solar under a 20-year power purchase agreement with Duke Energy Carolinas.

Repowering of Genesee 1 and 2, Including Battery Storage

The repowering of Genesee 1 and 2 will provide an additional 538 MW of net capacity of baseload power generation to the Alberta Power Pool and will have an expected capital cost of $997 million. The repowered assets will deploy best in class technology, reducing the carbon intensity of Genesee Units 1 and 2 to 0.35 tonnes CO_2e/MWh. Repowering Genesee 1 and 2 is scheduled to be completed in 2024, accelerating Capital Power's plans for a low carbon future.

On December 2, 2021, Capital Power announced plans to construct up to 210 MW of batteries at Genesee. The Capital Cost of the battery project is $195 million and will complement the repowered Genesee units 1 and 2, ensuring the asset complies with the AESO's MSSC limit. Until the MSSC limit is increased by the AESO, the battery will only be deployed in the event of either Genesee 1 or 2 tripping offline, ensuring no more than the current MSSC limit is lost to the AESO system.

<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 Commodities teams. 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 facilities, contracted facilities 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 power, 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 Commodities teams:

- manage price and volume risk in Capital Power's commodity portfolio;
- set generation unit offer strategy for electricity and ancillary services;
- acquire and schedule delivery of natural gas supply used to generate electricity; and
- ensure 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 independent power producers, financial entities, utilities, hedge funds, public and private investors, infrastructure funds, etc. in the energy and environmental commodities markets and for asset development and acquisition.

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, Texas, Illinois 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 and market intelligence, 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 13.3% of the dispatchable merchant generation capacity in the market.

In regulated, bi-lateral and centrally-planned markets, 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 Social and Governance Disclosure

Capital Power's ESG reporting practices reflect our commitment to transparency and disclosure. This commitment is demonstrated through integrating ESG and financial disclosure in Capital Power's third Integrated Annual Report, being published in February 2022. The Integrated Annual Report aligns to the Global Reporting Initiative and Sustainability Accounting Standards Board. Additionally, Capital Power voluntarily reports on climate change and water security-related disclosures through the Carbon Disclosure Project, receiving B scores for both. Capital Power publishes an annual Climate Change Disclosure Report (CCDR), which is aligned with the recommendations of the Financial Stability Board's Task Force on Climate-related Financial Disclosures.

We measure and report our performance on an ongoing and comprehensive basis and, in 2021, 25% of executive short-term incentive pay was based on the company meeting its ESG targets. In 2022, 25% of executive short-term compensation and 15% of non-executive short-term incentive pay will be based on the fulfillment of ESG objectives, and 20% of 2022 executive and leadership performance share units will include ESG elements demonstrating the continued emphasis being placed on sustainability in our overall corporate strategy. The Board receives quarterly reports on ESG metrics, which are also reported in the 2021 Integrated Annual Report.

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.

Canadian Federal Government

Greenhouse Gas Regulation – Coal Generation

The *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* (GHG Regulations) apply a performance standard of 0.420 tonnes of CO_2 emissions per gross output in MWh per year (tCO_2/MWh), which is intended to represent the intensity level of natural gas combined cycle technology. On February 17, 2018, the federal government published the final amendments to the GHG Regulations. Under these amendments, coal units will have to meet the performance standard of 0.42 t CO_2/MWh on December 31, 2029. Alberta's date for the phase out of use of coal for electricity generation is December 31, 2030.

Greenhouse Gas Regulation – Natural Gas Generation

On February 17, 2018, the Government of Canada enacted *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. Under the regulations, coal units converted to natural gas (coal-to-gas, or CTG) units were granted 0, 5, 8 or 10 years of additional operational life beyond their coal-fired end-of-useful-life (EoUL) 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 dioxide per MWh. Boilers that meet more stringent efficiency requirements are permitted to operate up to 10 years post EoUL.

For gas turbines, large units are subject to a 0.42 tCO_2/MWh standard, while small units are subject to a 0.550 tCO_2/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 regulation included provisions grandfathering existing units such that Clover Bar, Joffre, Shepard and Island Generation are not impacted by the standards.

Pan-Canadian GHG Framework

The *Greenhouse Gas Pollution Pricing Act (GGPPA)* sets out a federal carbon pricing system based on a two-pronged approach: (1) an economy-wide 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 applies to large industrial facilities (OBPS Regulations), which is administered by Environment and Climate Change Canada (ECCC). The GGPPA 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 are equivalent to the federal standard. Under the GGPPA, the federal carbon price started at $20 per tonne in 2019 and increases 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.

On September 20, 2020, the Minister of the Environment and Climate Change informed the governments of Ontario the provincial carbon pollution pricing systems for industrial facilities meet the federal government's minimum stringency benchmark requirements for equivalent pricing carbon pollution for the sources that they cover. As a result, the Government of Canada will not apply its OBPS in the province.

The Government of Canada ceased to apply the federal carbon pricing system for industry in Ontario on January 1, 2022.

The Government of Alberta repealed its economy-wide carbon tax on May 30, 2019. The Government of Canada therefore added Alberta to the list of provinces that would be subject to the federal carbon pricing system of the GGPPA in order to implement the fuel charge. For Alberta, the rates became effective on January 1, 2020, with future increases taking effect in April of each year for liquid, gaseous and other solid fuels. Capital Power facilities are exempt from the federal fuel charge since they are covered by TIER.

In August 2021, the Government of Canada updated the federal regulatory benchmark to assess if the provincial GHG regulatory systems meet the OBPS Regulations. The regulatory benchmark is a key component of Canada's path forward for carbon pricing post-2022. This update includes confirming the national minimum price on carbon pollution will escalate at $15/tonne to $170/tonne in 2030, and requiring that by December 31, 2022, every province and territory must have either completed legislative or regulatory changes to implement the 2023-2030 price increases or published a commitment to these price increases. The Government of Canada will assess provincial and territorial submissions against the updated federal benchmark criteria in 2022 for the 2023 to 2030 period. To provide certainty to residents and businesses and to allow carbon pricing systems to function effectively, where the federal backstop applies in 2023 it will remain in place until at least the end of 2026. The federal government will conduct an interim assessment in 2026 of provincial and territorial systems to confirm that systems continue to meet the benchmark criteria for the 2027-2030 period, taking stringency into account as the primary factor.

Federal Climate Plan and Proposals

On December 11, 2020, the Government of Canada released its updated climate plan (the Federal Plan). The Federal Plan sets out a range of measures and proposed policies across multiple sectors that are intended to enable Canada to meet and exceed its current 2030 greenhouse gas reduction commitments under the Paris Agreement, and also set Canada on a path to achieving net-zero by 2050. Among other things, the Federal Plan proposes to increase the carbon price by $15 per tonne per year after 2022 until achieving a price of $170 per tonne in 2030; review standards used to assess equivalence of provincial carbon frameworks; make investments to advance smart renewable energy and grid modernization projects to enable the clean grid of the future; work with provinces and territories to help build key intertie projects; and make funding available and develop strategies to support further deployment of various decarbonization technologies including carbon capture, utilization and storage and hydrogen.

On April 22, 2021, Prime Minister Trudeau announced that Canada will increase its emissions reduction target to be 40-45% below 2005 levels by 2030, compared to the previous target of 30%. The 40-45% emissions reduction was subsequently incorporated in *the Canadian Net-Zero Emissions Accountability Act*, which received Royal Assent on June 29, 2021, and was reflected in Canada's enhanced Nationally Determined Contribution (NDC) that was submitted to the United Nations on July 12, 2021.

The Federal Government also confirmed in July 2021 that the minimum price on carbon will increase by $15 per tonne each year starting in 2023 to a level of $170 per tonne in 2030, as set out in the Federal Plan, and advised that the "benchmark" stringency framework will be updated to ensure all provincial and territorial pricing systems are comparable in terms of stringency and effectiveness. Provinces and territories will continue to have the flexibility to implement the type of system that makes sense for their circumstances as long as they align with the benchmark. Additional information or details regarding sector-specific targets or measures arising from the new targets, relative to the policies that have been outlined in the Federal Plan, have not been provided at this time. The Company will incorporate the new targets as part of its ongoing assessment of the potential impacts of Federal carbon policy for Capital Power's existing facilities and prospective interests in the Canadian market.

On September 21, 2021, the Canadian Federal Election resulted in the re-election of the Liberal Party of Canada as Government in a minority Parliament. The Government of Canada has subsequently affirmed its commitment to the aforementioned carbon policies, and also announced a goal of transitioning Canada to a net-zero emitting electricity grid by 2035. A consultation process regarding additional measures to meet Canada's new emissions targets is expected to be initiated in the first quarter of 2022.

Management continues to assess the potential impacts the proposed elements of the updated Federal Plan may have for Capital Power's existing facilities and prospective interests in its Canadian markets, and intends to participate in forthcoming processes, which have yet to be scheduled, to discuss the key elements proposed as part of the Federal Plan.

Alberta

Off-Coal Agreement

On November 24, 2016, Capital Power announced it had 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 was to receive cash payments from the Province of Alberta of $52.4 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. The Government of Alberta conducted an audit on the calculation of net book values driving the compensation payments and has withheld approximately $2.7 million from each of the payments from 2017 through 2021. 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 payments. This has resulted in a reduction of $1.5 million to the government compensation amount recorded for each of the corresponding years from 2017 through 2021. The respective deferred revenue and government grant receivable amounts were likewise adjusted to reflect total payments over the 14-year term of $712 million. Capital Power is required to cease coal-fired emissions from Genesee 1, Genesee 2 and Genesee 3 by the end of 2029. In December 2020, Capital Power announced its plan to cease coal-fired operations by the end of 2023, six years earlier than required by the Federal regulations.

Climate Change Strategy

On January 1, 2020, the Government of Alberta replaced the Carbon Competitiveness Incentive Regulation (CCIR) with the Technology Innovation and Emissions Reduction Regulation (TIER) for large industrial emitters. Under TIER, the carbon price for large emitters was $40 per tonne in 2021. On December 1, 2021, Alberta Environment and Parks announced that the 2022 carbon price under TIER will be $50 per tonne of carbon dioxide equivalent (CO_2e).

To meet TIER requirements, facilities can physically reduce their emissions or:

- use credits from facilities that have reduced their emissions to below their respective targets;
- use emission offsets from organizations that are not regulated by TIER, but which have voluntarily reduced their emissions; or
- pay into the TIER Fund at $40/ tCO_2e in 2021.

Specific to the electricity industry, the benchmark is set at 0.37 tCO_2e/MWh. If a facility's emissions exceed 0.37tCO_2e/MWh, the resulting compliance obligation can be met through the use of Emission Performance Credits (EPCs) or offsets, or through payment to the Technology Innovation and Emissions Reduction Fund.

In March 2021, AEP initiated Alberta's Climate Policy Engagement process in response to Canada's Federal Plan. The Government of Alberta structured the process to understand stakeholder climate-related initiatives and understand how Alberta can support those initiatives. Capital Power participated in the process and expressed support for Alberta's existing TIER framework for electricity. The Government of Alberta has not released a final report regarding the process or advised of potential next steps.

TIER imposes limits on the use of EPCs and offsets within each compliance year, which are 60% for 2021. TIER also imposes expiry periods on TIER eligible carbon credits. Vintages 2015/2016 can only be used for up to 40% of the total compliance obligation of a facility for 2021 compliance and will expire after the

2021 compliance submission in June 2022. Vintage 2017 and newer credits have an 8-year vintage expiry period.

Capital Power's 2021 TIER compliance obligation must be paid in the second quarter of 2022. The Company intends to retire expiring 2015/16 carbon credits for the maximum 40% of its 2021 compliance obligation and purchase fund credits at the $40 per tonne 2021 cost for the remaining 60% of our 2021 obligation. The newer vintage offsets and emission performance credits in inventory will be saved for use in future years when the carbon price associated with the TIER Fund is expected to increase. Therefore, the approximate total cost of compliance for Capital Power for the 2021 reporting period, split by Capital Power's generating assets for the 2021 reporting period (under TIER), is comprised as follows:

- Genesee 1 and 2 are expected to pay approximately $84.4 million.
- Genesee 3 is expected to be approximately $58.6 million.
- Genesee Mine has opted into the TIER program and the cost for 2021 is expected to be approximately $0.4 million.
- Clover Bar is expected to be approximately $2.3 million.
- Shepard Energy Center is expected to be approximately $0.1 million (representing Capital Power's 50% interest).

Under the operating approvals for Genesee 3, Capital Power was required to offset its emissions to the equivalent of a natural gas combined cycle facility. This requirement is now met through regulation under the current TIER program. Capital Power also voluntarily offsets 100% of its Scope 2 emissions from power consumed by all our facilities by retiring offsets and RECs against those emissions.

Capital Power has been acquiring offsets for over a decade and has entered into more than 100 offset purchase agreements across North America. Capital Power invested approximately $62 million in Alberta Compliance offsets in 2021.

Air Emission Regulations

The Federal and Alberta governments both support coal-to-gas conversion to reduce emissions, maintain reliability, and help avoid stranded assets. Air emissions from the Alberta electricity sector are managed by the 2003 CASA Framework, which when developed did not anticipate CTG Units. In 2018, to address this gap, the Alberta government developed NOx standards for CTG Units based on recommendations made by CASA.

On February 20, 2018 the Government of Alberta issued the CTG NO_x Policy. According to the CTG NO_x Policy, CTG subcritical units' NO_x emissions would be limited to 50% of their 2003 CASA baseline emissions. Converted Genesee 1 and 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 EoUL of the converted units. To demonstrate compliance with the NO_x emission standards, units will have an annual emission intensity test. Exceeding the maximum 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 for consideration.

In September 2021, AEP released the draft Ambient Air Quality Objectives (AAQOs) for nitrogen dioxide (NO_2), sulphur dioxide (SO_2) for consultation. The draft AAQOs will not impact the current Environmental Protection and Enhancement Act (EPEA) approvals for the Genesee repowering units, which were approved as an amendment to the existing Genesee permits but will be a consideration in the EPEA renewal process which will commence in 2024 prior to expiry of the current permits in 2026. Management is assessing the potential impacts, if any, of the draft AAQOs on Genesee and Cloverbar Energy Centre future EPEA renewals.

Alberta Environment Water Act Approvals Business Design

In June 2021, AEP started a consultation process to develop new surface water quality management frameworks (Frameworks) for the North Saskatchewan, Battle and Upper Athabasca rivers. The Frameworks establish clear regional objectives for water quality and include thresholds that require a management response when exceeded to ensure the rivers can support water needs for communities, aquatic habitat and a vibrant economy.

This initiative is relevant to Capital Power's existing North Saskatchewan River water diversion licenses for Genesee and the Clover Bar Energy Centre.

British Columbia (BC)

The Government of BC announced plans, effective April 1, 2018, to escalate its $30 per tonne carbon tax by $5 per tonne per year until it matched the Federal carbon tax floor of $50 per tonne in 2022. On April 1, 2021, BC's carbon tax rate rose from $40 to $45 per tCO_2e. The rate is scheduled to increase to $50 per tonne on April 1, 2022. To help provide relief during the COVID-19 pandemic, a previously scheduled increase was postponed in 2020. Capital Power's operations in BC do not have any carbon tax exposure.

Ontario

On July 4, 2019, the Government of Ontario published their final Greenhouse Gas Emissions Performance Standards (EPS). The first compliance period came into effect on January 1, 2022 when the federal government removed Ontario from the GGPPA, which exempted Ontario from being subject to the output-based pricing system.

The EPS was created under the Emissions Performance Standards Regulation. The EPS includes excess emissions units (EEUs) and emissions performance units (EPUs) as compliance instruments which can be used to satisfy a facility's compliance obligation. EEUs must be distributed to facilities beginning in the first year after the first compliance period. The cost EEU will match the federal carbon price. The EPS did not consider offsets.

The Government of Ontario (Ontario) released on October 22, 2021 the final amendments to:

- Greenhouse Gas Emissions Performance Standards regulation (O. Reg.241/19 or the EPS Regulation) and the incorporated GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit; and

- Greenhouse Gas Emissions: Quantification, Reporting and Verification regulation (O. Reg. 390/18 or the Reporting Regulation) and the incorporated Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions.

The transition from the federal OBPS came into effect on January 1, 2022. The electricity performance standard for electricity sector is 0.370 tCO_2e/MWh and the cogeneration standard will be based on 80% efficient cogeneration system policy. Ontario has chosen not to include offsets for compliance in its EPS amendments.

Capital Power's Ontario facilities have power purchase contracts with provisions that trigger amendments as a result of changes in GHG cost, the effect of which will enable recovery of most of the imposed federal or provincial carbon compliance costs.

United States

Greenhouse Gas Regulation

The US EPA's Cross-State Air Pollution Rule requires 28 eastern states to reduce SO_2 and NO_x emissions from power facilities 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. The Company ceased operations of Southport and Roxboro at the end of March 2021, and the compliance costs for SO_2 and NO_2 allowances for the short 2021 operating period will likely total approximately $4,000. The Decatur and Arlington facilities are also subject to the Acid Rain Program but have been allocated a sufficient amount of credits to cover the annual compliance obligation under this program.

On July 8, 2019, the US EPA published the final Affordable Clean Energy Rule (ACE) to repeal and replace the Clean Power Plan (CPP). Under ACE, states are required to conduct a unit specific evaluation of the potential for heat rate improvements at existing fossil fuel facilities, which will then be used to establish emission standards for units within their state. States 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. The final rule prohibits state plans from allowing averaging or trading among units for compliance purposes.

ACE took effect on September 6, 2019 and directed states to submit compliance plans within 3 years. An assortment of parties, including twenty-five states, environmental and public health NGOs, and a number of utility companies subsequently challenged ACE in the D.C. Circuit Court. On January 19, 2021, the Court issued a ruling that struck down the validity of ACE and remanded it back to the US EPA. President Biden subsequently directed the US EPA to review ACE. The US EPA is expected to promulgate new CO_2 standards for existing power plants under the Clean Air Act but has yet to release proposals for a new rule.

<u>Health, Safety and Environment</u>

Health, Safety and Environment Policy

Capital Power is in the business of constructing, operating, and maintaining power generation and related facilities. This set of activities can present significant risks to human health and safety, and to the environment, if not properly managed. This Health, Safety and Environment Policy (the Policy) is intended to create, implement, and maintain a Health, Safety and Environment (HSE) Management System that enables minimization of occupational injury and illness, and negative impacts to the environment, in a socially responsible and sustainable manner by ensuring:

- the promotion of a zero-injury safety culture, which includes an obligation to promote and maintain the health, safety and welfare of all workers;
- environmental responsibility;
- compliance with all applicable laws and regulatory requirements;
- proactive identification and management of health, safety and environment-related risks;
- consultation, collaboration and co-operation with employees and contractors on HSE matters;
- the continuous review and improvement of this Policy and the HSE Management System;
- appropriate goals are established and performance is monitored in respect of those goals;

- contractors align with the Policy; and

- employees, contractors and third parties understand their HSE responsibilities and possess the required competencies and training to perform their job responsibilities, including hazard identification, hazard control and monitoring of hazard control effectiveness.

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

Capital Power manages its HSE risks through a company-wide HSE Management System 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 objectives are established annually to promote Capital Power's HSE stewardship and are measured through the HSE Performance Index (Index). The Index measures performance by using a combination of leading and lagging performance indicators. Where lagging indicators measure the "end-results", leading indicators recognize and focus attention on proactive activities and continuous improvement.

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, near miss events and incidents. These events are tracked and analysed for trends, with preventative actions taken to address 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 and achievements include the following activities:

- 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 12% by 2023.

- 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 Airshed zone. The zone is approximately 62 thousand square kilometres and spans from just west of Edmonton 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 reclaim land from previously mined areas and return it to productive farmland 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.

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

Specific health and safety initiatives and achievements include the following activities:

- Achievement of an HSE Performance Index of 1.08. This is the 8th consecutive year the Index has finished at or above the target of 1.0.

- Development of a mandatory Investigation 101 training program for leadership. The training was fully implemented in 2021. Applying formal investigation training demonstrates continuous improvement which will reflect positively throughout the Company as it will improve the identification of causes and effective corrective actions to prevent reoccurrence.

- A Significant Event Review Committee which reviews incident investigations and conducts root cause analysis of recordable injury and serious near miss events. The Committee ensures investigations are completed in a timely manner and completed at a level appropriate for the incident, action plans are identified, and learnings are shared across the organization.

- Applicable Capital Power's offices, Power operating facilities and construction sites have HSE representatives, or an established health and safety committee as required by regulations.

- HSE Improvement Plans were implemented at all facilities and for the construction and engineering group.

- Achievement of the Certificate of Recognition (COR). A COR is awarded to employers who develop health and safety programs that meet established standards. A COR shows that the employer's health and safety management system has been evaluated by a certified auditor and meets provincial standards. These standards are established by Occupational Health and Safety (OHS).

- Establishment of standardized gas fleet health and safety procedures. The project consisted of establishing a fleet wide permitting program and associated procedures for critical activities including hazardous energy isolation (lock out tag out), ground disturbance, hot work, and confined space. The implementation occurred in 2021 and continues into 2022.

- Implementation of enhancements to the HSE software program. Enhancements to the program made in December 2021 will allow for further dissection and trending analysis of incidents, near miss, hazard identifications, and inspection findings.

COVID-19 Pandemic Response and Planning

Capital Power continued to place the utmost importance on the health and safety of its employees as the COVID-19 pandemic carried on through 2021. Highlights of the response and ongoing planning include the following:

- remote work, which was enacted March 13, 2020, continues with physical access to Capital Power sites restricted to workers that are essential to reliable operations;

- COVID-19 specific hazard assessments were completed for all work locations including our generating facilities, office locations, and work from home;

- fleet wide protocols and procedures including signage, enhanced cleaning, site access screening protocols and temperature checks, COVID-19 specific personal protective equipment, a suspected case procedure including contact tracing, and return to work protocols for employees and contractors;

- conduct monthly inspections at all sites to ensure adherence to COVID protocols;

- a COVID-19 education and awareness campaign including 12 "town hall" meetings where employees were provided information on COVID-19 and vaccination; and

- implementation of an organization-wide COVID-19 vaccination policy which requires all employees, contractors and visitors to either be fully vaccinated or show a negative COVID-19 test within 72 hours of requesting access to a Capital Power site.

There have been no material COVID-19 related impacts to operations at any plant or any facility.

People

As at December 31, 2021, the total number of persons employed by Capital Power is 773[2]. As at December 31, 2021, approximately 691 full-time, part-time, temporary and casual employees work in Capital Power's Canadian operations and 82 are employed in Capital Power's US operations.

There are three Canadian labour unions, in four bargaining units, which together represent approximately 33% of Capital Power's Canadian labour force and approximately 29% 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 facility;

- the International Brotherhood of Electrical Workers Local 1007, which represents electrical, instrument and mechanical tradesmen, coal facility operators, equipment and crane operators, utility workers, tool servicemen and related employees at the Genesee power facility;

- the UNIFOR Local 829, which represents power engineers at the Genesee power facility; and

- the UNIFOR Local 1123, which represents shift engineers, electrical and instrumentation technicians and mechanical maintenance technicians at Island Generation.

Bargaining with CSU 52 will start in Q1 of 2022. 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	December 23, 2018	December 18, 2021
IBEW Local 1007	Edmonton, AB	December 20,2020	December 16, 2022
UNIFOR Local 829	Edmonton, AB	December 20, 2020	December 17, 2022
UNIFOR Local 1123	Campbell River, BC	May 1, 2021	April 30, 2025

[2] This number excludes board members and employees on long-term disability.

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 paid for by independent power producers and are compensated subject to market forces, rather than regulation payors. 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 and 2. As of December 31, 2020, all PPAs with the Balancing Pool as "PPA Buyer" have expired. In light of the expiry, the Balancing Pool no longer has an active position in the wholesale electricity market and the role of market participant has reverted back to the generation facility owner. The generation facility owner now has sole authority to make decisions regarding if and how the underlying generation assets are operated in the market. Power from 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 facility 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 Energy Resources Conservation Board 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.

Updates on the Government of Alberta's climate policy, discussed above can be found in the "Business of Capital Power – Environmental Regulation – Alberta – Climate Change Strategy" section including details on how that policy will impact the electricity sector in Alberta.

British Columbia

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 imports and 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 independent power producers (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.

In June 2021, BC Hydro published their draft Integrated Resource Plan (IRP). The draft provided that BC Hydro was not intending to renew the long-term tolling arrangement for Capital Power's Island Generation facility at Campbell River on Vancouver Island, which expires in April 2022. BC Hydro affirmed this intention in the Final IRP that was filed with the BC Utilities Commission (BCUC) in December 2021 and which will be the subject of a BCUC proceeding in 2022. The Company continues to believe the Island Generation facility is needed to ensure secure and reliable electricity supply for homes and businesses on Vancouver Island and in Metro Vancouver and will actively participate in the forthcoming BCUC regulatory proceeding in 2022.

Separate from its IRP development process, in September, BC Hydro indicated to the BCUC that, in response to issues with the submarine cable between Vancouver Island and the mainland, it would initiate further discussions with Capital Power to determine if Island Generation can provide economic backup capacity while repairs are undertaken over the next two to four years. BC Hydro noted in the Final IRP document that discussions in this respect were ongoing. On October 25, 2021, the Government of British Columbia released "CleanBC: Roadmap to 2030" which identified a number of measures and initiatives that British Columbia would undertake as part of a stronger and more ambitious plan to achieve its 2030 emissions targets and net-zero emissions by 2050. Among other measures, the Government of British Columbia intends to increase the Clean Electricity Delivery Standard for the BC Hydro integrated grid to 100%, which it expects BC Hydro to meet in part by phasing out its remaining natural gas-fired facilities on the grid by 2030. While full details regarding implementation of this and other components of the plan are not known, particularly the implications if any for BC Hydro's forthcoming final IRP, this component of the Roadmap could limit the term for any re-contracting of the Island Generation facility.

Ontario

Ontario has a "hybrid market" for electricity and related products administered by the IESO. The IESO Administered Market produces hourly prices for energy and operating reserve, but most existing resources are either contracted or rate-regulated. Hydro One operates approximately 97% of Ontario's transmission network. The electricity sector is regulated by the Ontario Energy Board. Under the *Electricity Act, 1998* the Minister of Energy, Northern Development and Mines is required to issue a long-term energy plan during the period prescribed by regulation.

Capital Power has ownership interests in three thermal gas facilities and two wind projects in Ontario. The York Energy Centre was commissioned in 2012 and is the largest quick-response gas-fired facility in Ontario, operating under contract with the IESO. East Windsor began commercial operations in 2009 and operates under contract with the IESO. Goreway began commercial operations in 2009 and operates under contract with the IESO.

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.

In June, 2020 the Minister of Energy, Northern Development and Mines (MENDM) issued notice of its intent to revoke the regulatory requirement to publish a long-term energy plan and provided notice of its intention to embark on designing a revised electricity planning framework. In January 2021, MENDM announced that the regulation requiring the release of the Long-term Energy Plan (LTEP) every three years has been revoked effective January 1, 2021. According to the MENDM notice, removal of this requirement is part of its plan to reform the province's long-term energy planning process.

In 2021, the IESO initiated consultations regarding competitive processes through which it would intend to procurement resources under two general timeframes: Medium Term (MT) procurement, which would largely focus on potential recontracting for existing resources, and Long Term (LT) procurement, which would largely focus on procurement of new resources. The Honourable Todd Smith, Minister of Energy, issued a letter to the IESO on November 10, 2021, providing guidance on both the MT request for proposals (MT RFP) and LT RFP processes. The IESO is finalizing the structure for the MT RFPs and will launch consultations on the LT RFP in early 2022. The Company continues to participate in the RFP design processes to ensure reasonable opportunities to recontract existing assets at the end of their respective terms and for future investment opportunities.

On October 7, 2021, the IESO issued a report assessing the impacts of potentially phasing out natural gas generation by 2030, which it had initiated earlier in 2021. The IESO concluded that doing so was not feasible and would lead to blackouts and significantly higher costs associated with replacement generation and additional transmission infrastructure. In response to the report, The Honourable Todd Smith, Minister of Energy, issued a letter directing the IESO to undertake two initiatives. First, the IESO is to evaluate a moratorium on new natural gas generating stations in Ontario and to consider whether alternative sources of electricity can meet Ontario's objectives of affordability, reliability, and environmental stewardship. Second, Minister Smith asked the IESO to develop an achievable pathway to phase out natural gas generation and ultimately achieve zero-emissions in the electricity system, with consideration to a number of specific elements including the reliability of the electricity system; the cost to electricity ratepayers; the timeline on which this objective would be achievable; the possibility of maintaining existing generating facilities but replacing natural gas with green fuels such as hydrogen and renewables. The IESO was directed to provide its report by November 2022. The Company will participate in the IESO's consultation processes once initiated by the IESO.

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 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.

<u>North Carolina</u>

Most of North Carolina is not part of an RTO or ISO. Thus, in most areas of the state, transactions are bilateral and must be scheduled through the incumbent utility. Capital Power owns three facilities in North Carolina: Southport, Roxboro, and Beaufort, which are all in the non-RTO part of North Carolina.

Beaufort is a 15 MW solar project contracted with Duke Energy Progress, LLC through 2030. Southport and Roxboro were QFs that were contracted with Duke Energy Progress.

Southport and Roxboro ceased operations on March 31, 2021, and are currently being decommissioned by D.H. Griffin, who is a large contractor with significant demolition, salvage, and reclamation experience of industrial sites. Decommissioning is expected to conclude mid-2022 with the Southport property reverting back to Duke Energy Corporation as owner and the Roxboro property to be transacted to a yet-to-be-identified new owner.

<u>New Mexico</u>

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.

<u>Alabama</u>

Capital Power owns Decatur, an 885 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 expires December 31, 2032.

<u>Kansas</u>

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 its output under a financial proxy revenue swap agreement over a 10-year term into mid-2027 with Allianz Risk Transfer, as further described in "Business of Capital Power – US Contracted Facilities – Bloom".

Arizona

Capital Power owns Arlington Valley, a 600 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, most 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 an investment grade, load-serving entity under a summer tolling agreement through 2031 and provides capacity and energy to a credit-worth counterparty under a non-summer Heat Rate Call Option through 2025, as further described in "Business of Capital Power – US Contracted Facilities – Arlington Valley".

Illinois

Capital Power owns Cardinal Point Wind, a 150MW generation facility located in McDonough and Warren Counties, Illinois. Cardinal Point is in the portion of the state that 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. Cardinal Point is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Cardinal Point operates under a fixed-price financial hedge contract over 12-year term with an investment grade US financial institution, as further described in "Business of Capital Power – US Contracted Facilities – Cardinal Point".

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 operates under a fixed-price financial hedge contract over a 12-year term with an investment grade US financial institution, as further described in "Business of Capital Power – US Contracted Facilities – New Frontier".

Texas

Capital Power owns Buckthorn Wind, a 101 MW wind facility located approximately 60 miles southwest of Dallas in Erath County, Texas. The state is almost entirely part of the ERCOT, an RTO that operates the transmission system and a centrally dispatched market in most of the state of Texas.

Buckthorn Wind operates under two financial hedges with an investment grade US financial institution, as further described in "Business of Capital Power – US Contracted Facilities – Buckthorn Wind".

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 Integrated Annual Report for the year ended December 31, 2021 which section is incorporated herein by reference and is available on SEDAR.

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COMMON AND PREFERRED DIVIDENDS

Common Dividends

For the three most recently completed financial years, the Company has declared the following: (i) on July 30, 2021, the Company announced a 6.8% dividend increase for its Common Shares effective for the third quarter 2021 dividend for an annualized dividend of $2.19 per Common Share, (ii) on July 30, 2020, the Company announced a 6.8% dividend increase for its Common Shares effective for the third quarter 2020 dividend for an annualized dividend of $2.05 per Common Share, (iii) on July 29, 2019, the Company announced a 7.3% dividend increase for its Common Shares effective for the third quarter 2019 dividend for an annualized dividend of $1.92 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 subsidiaries, current and anticipated cash needs, the requirements of any future financing agreements and other factors that the Board may deem relevant.

Effective December 31, 2021, the Company suspended its DRIP for its Common Shares. Shareholders participating in the DRIP began receiving cash dividends on the January 31, 2022 payment date. See "Common and Preferred Dividends – Dividend Reinvestment Plan".

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**
15 Feb 19	$0.4475
26 Apr 19	$0.4475
29 Jul 19	$0.480
25 Oct 19	$0.480
21 Feb 20	$0.480
1 May 20	$0.480
30 Jul 20	$0.5125
30 Oct 20	$0.5125
18 Feb 21	$0.5125
29 Apr 21	$0.5125
30 Jul 21	$0.5125
26 Oct 21	$0.5475
23 Feb 22	$0.5475

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 five year period ending December 31, 2020. The fixed cumulative dividends was $0.765 per share per annum during this five year period.

On December 31, 2020, the annual fixed dividend rate on the Series 1 Shares was reset pursuant to their terms to 2.621% for five-year period ending December 31, 2025. The fixed cumulative dividends will be $0.65525 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**
15 Feb 19	$0.19125
26 Apr 19	$0.19125
29 Jul 19	$0.19125
25 Oct 19	$0.19125
21 Feb 20	$0.19125
1 May 20	$0.19125
30 Jul 20	$0.19125
30 Oct 20	$0.19125
18 Feb 21	$0.1638125
29 Apr 21	$0.1638125
30 Jul 21	$0.1638125
26 Oct 21	$0.1638125
23 Feb 22	$0.1638125

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**
15 Feb 19	$0.3408125
26 Apr 19	$0.3408125
29 Jul 19	$0.3408125
25 Oct 19	$0.3408125
21 Feb 20	$0.3408125
1 May 20	$0.3408125
30 Jul 20	$0.3408125
30 Oct 20	$0.3408125
18 Feb 21	$0.3408125
29 Apr 21	$0.3408125
30 Jul 21	$0.3408125
26 Oct 21	$0.3408125
23 Feb 22	$0.3408125

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**
15 Feb 19	$0.327375
26 Apr 19	$0.327375
29 Jul 19	$0.327375
25 Oct 19	$0.327375
21 Feb 20	$0.327375
1 May 20	$0.327375
30 Jul 20	$0.327375
30 Oct 20	$0.327375
18 Feb 21	$0.327375
29 Apr 21	$0.327375
30 Jul 21	$0.327375
26 Oct 21	$0.327375
23 Feb 22	$0.327375

The Series 7 Shares paid 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.

On December 31, 2021, the Company redeemed all of the issued and outstanding Series 7 Shares at a price of $25.00 per share for an aggregate total of $200 million.

The following dividends were declared on the Series 7 Shares for the three most recently completed financial years:

Dividends Declared	
Declaration Date	**Dividend per Share**
15 Feb 19	$0.375
26 Apr 19	$0.375
29 Jul 19	$0.375
25 Oct 19	$0.375
21 Feb 20	$0.375
1 May 20	$0.375
30 Jul 20	$0.375
30 Oct 20	$0.375
18 Feb 21	$0.375
29 Apr 21	$0.375
30 Jul 21	$0.375
26 Oct 21	$0.375

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 for the three most recently completed financial years:

Dividends Declared	
Declaration Date	**Dividend per Share**
15 Feb 19	$0.359375
26 Apr19	$0.359375
29 Jul 19	$0.359375
25 Oct 19	$0.359375
21 Feb 20	$0.359375
1 May 20	$0.359375
30 Jul 20	$0.359375
30 Oct 20	$0.359375
18 Feb 21	$0.359375
29 Apr 21	$0.359375
30 Jul 21	$0.359375
26 Oct 21	$0.359375
23 Feb 22	$0.359375

The Series 11 Shares pay fixed cumulative dividends of $1.4375 per share per annum, yielding 4.15% 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, 2024.

The following dividends have been declared on the Series 11 Shares since the date of issuance of such shares:

Dividends Declared	
Declaration Date	**Dividend per Share**
16 May 19	$0.1772(1)
29 Jul 19	$0.359375
25 Oct 19	$0.359375
21 Feb 20	$0.359375
1 May 20	$0.359375
30 Jul 20	$0.359375
30 Oct 20	$0.359375
18 Feb 21	$0.359375
29 Apr 21	$0.359375
30 Jul 21	$0.359375
26 Oct 21	$0.359375
23 Feb 22	$0.359375

Note:
(1) Initial quarterly dividend represents the period from May 16, 2019 (the date of issuance of the Series 11 Shares) to June 30, 2019.

Dividend Reinvestment Plan

On January 1, 2012, the Company launched a DRIP, under which eligible shareholders were able to elect to participate 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 the DRIP, reducing the discount rate from a 5% discount to the average market price to a discount rate of 3%, effective the third quarter 2014 dividend. Subsequently, on March 25, 2015, the Company announced the suspension of the DRIP following the April 2015 dividend payment.

On July 30, 2020, the Company reinstated the DRIP. Eligible shareholders were entitled to participate in the DRIP commencing with the Company's third quarter 2020 cash dividend. Shareholders that were enrolled in the DRIP upon suspension in June 2015, and remained enrolled with the plan administrator, automatically resumed participation in the DRIP upon reinstatement. New Common Shares issued under the reactivated DRIP were issued at a discount rate of 3% to the average closing price on the TSX for the 10 trading days immediately preceding the applicable dividend payment date.

Subsequently, on July 30, 2021, the Company announced a reduction in the discount percentage for the DRIP, reducing the discount rate from a 3% discount to the average market price to a discount rate of 1%, effective the third quarter 2021 dividend. On October 27, 2021, the Company announced the suspension of the DRIP following the October 2021 dividend payment.

If the DRIP is reinstated, 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 the DRIP is reinstated, 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 will be 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.

Since the Company's DRIP was introduced and as of the date of this AIF, 6,775,350 Common Shares have been issued pursuant to the DRIP at a weighted average price of $27.04. To date, no pro-ration 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, 2021, after giving effect to the redemption of Series 7 Shares discussed further below under "Capital Structure – Preference Shares", there were 116,193,681 Common Shares, 5 million Series 1 Shares, 6 million Series 3 Shares, 8 million Series 5 Shares, 6 million Series 9 Shares, 6 million Series 11 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.

On May 25, 2021 the Company announced it entered into an agreement with a syndicate of underwriters to purchase on a bought deal basis, an aggregate of 6,505,000 Common Shares, at an offering price of $38.45 per Common Share for total gross proceeds of approximately $250 million, along with an over-allotment option for up to an additional 975,750 Common Shares. On June 2, 2021, the Company completed an offering of 7,480,750 Common Shares, which included 975,750 Common Shares issued pursuant to the full exercise of the over-allotment option, for total gross proceeds of approximately $288 million. The net proceeds were used to fund growth and development initiatives and for general corporate purposes. Dividends are payable, as and if declared by the Board, on a quarterly basis on or about the last day of each month following the end of each fiscal quarter.

Normal Course Issuer Bid

On February 24, 2022, the Company announced that the Toronto Stock Exchange had approved the Company's normal course issuer bid to purchase and cancel up to 8,000,000 of its outstanding Common Shares during the one-year period from February 28, 2022 to February 27, 2023. As of the date of this AIF, no shares have been repurchased by the Company.

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 61,882 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 247,528 Common Shares), subject to certain exceptions for block repurchases.

On February 23, 2021, the Company announced that the Toronto Stock Exchange had approved the Company's normal course issuer bid to purchase and cancel up to 10,661,112 of its outstanding Common Shares during the one-year period from February 26, 2021 to February 25, 2022. As of the date of this AIF, no shares have been repurchased by the Company.

Pursuant to the rules of the Toronto Stock Exchange, the maximum number of Common Shares that could be purchased during the same trading day on the Toronto Stock Exchange was 87,397 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 349,589 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 as otherwise may be permitted by applicable securities regulatory authorities.

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 May 16, 2019, the Company issued 6 million Series 11 Shares at a price of $25.00 per Series 11 Share for aggregate gross proceeds of $150 million.

The Series 11 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 June 30, 2024. The dividend rate will reset on June 30, 2024 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.15%, provided that in any event, such rate shall not be less than 5.75%. The Series 11 Shares are redeemable by Capital Power, at its option, on June 30, 2024 and every five years thereafter.

The holders of the Series 11 Shares will have the right, at their option, to convert all or any part of their Series 11 Shares into Cumulative Floating Rate Preference Shares, Series 12 (Series 12 Shares), subject to certain conditions, on June 30, 2024 and every five years thereafter. Holders of the Series 12 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 4.15%, as and when declared by the Board.

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 paid 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).

On November 5, 2021 the Company announced its intention to redeem all of its 8,000,000 issued and Series 7 Shares on December 31, 2021 at a price of $25.00 per share for an aggregate total of $200 million, less any tax required to be deducted and withheld by the Company. All of the Series 7 Shares were redeemed on December 31, 2021.

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 again had the right to elect to convert all or any part of their Series 1 Shares into Series 2 Shares, subject to certain conditions, on December 31, 2020. Following the conversion deadline on December 16, 2020, 687,245 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, 2020. Effective December 31, 2020, the annual fixed rate for the Series 1 Shares for the next five-year period was reset to 2.621%.

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, 2025 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%.

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 July 20, 2021, Capital Power Corporation executed a 12-year US$150 million private placement of senior notes to partially refinance the 10-year US$230 million senior notes that matured in June 2021. These Series I Senior Guaranteed Notes were issued on October 28, 2021 and mature in October 2033. They bear an interest rate of 3.24% which will be paid semi-annually and rank pari-passu with the Company's other senior unsecured borrowings. The Note Purchase Agreement, by and among CPC (as issuer) and the Purchasers (as defined therein) prohibits the Company from making distributions if an event or condition has occurred and is continuing that would, with the lapse of time or giving of notice or both, constitute an event of default under the terms of the Note Purchase Agreement.

On October 9, 2020 Capital Power Corporation redeemed all of its outstanding 5.276% medium-term notes, due November 16, 2020, in the aggregate principal amount of $251,181,000. The redemption price was an aggregate amount of $257,614,750.13, including applicable early redemption premiums, as well as accrued and unpaid interest to and including the day immediately preceding the redemption date.

On October 1, 2020, Capital Power Corporation issued $350 million of senior unsecured medium-term notes due on October 1, 2032 with interest payable semi-annually at a rate of 3.147%, pursuant to the New Indenture as supplemented by a fourth supplemental Trust Indenture dated June 1, 2020.

On May 15, 2020, 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 2020 will be issued pursuant to the terms of the New Indenture.

On November 8, 2019, Capital Power Corporation issued $275 million of senior unsecured medium-term notes due on February 8, 2030 with interest payable semi-annually at a rate of 4.424%, pursuant to the New Indenture, as supplemented by a third supplemental Trust Indenture dated November 8, 2019.

On June 12, 2019, Capital Power Corporation closed $325 million private placement of senior notes. The senior notes consist of five tranches, two with 10-year terms, two with 12-year terms and one with a 15-year term. The two 10-year senior notes have an aggregate principal amount of $210 million that matures in June 2029 with a coupon rate of 4.56%. The two 12-year senior notes have an aggregate $65 million principal amount and matures in June 2031 with a coupon rate of 4.72%. The 15-year senior note has a $50 million principal amount and matures in June 2034 with a coupon rate of 4.96%. The Note Purchase Agreement dated as of June 12, 2019, by and among CPC (as issuer) and the Purchasers (as defined therein) prohibits the Company from making distributions if an event or condition has occurred and is continuing that would, with the lapse of time or giving of notice or both, constitute an event of default under the terms of the Note Purchase Agreement.

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 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 consisted of two notes with 10 and 15-year terms. The 10-year Senior Note had a principal amount of US$230 million that matured 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 various lenders as described below. Capital Power's credit facilities include: (i) an extendible syndicated facility of up to $700 million, with an accordion feature to increase the facility size by up to $300 million; and (ii) an extendible revolving club credit facility of up to $300 million. Both credit agreements were extended and amended in July 2021 transitioning them into Sustainability-Linked Credit facilities (SLCs). The 5-year, $1 billion SLCs reinforce Capital Power's ESG ambitions and commitments by introducing financial incentives to reach its ESG goals. The SLCs are structured with one key performance indicator with annual Sustainability Performance Targets aligned to one of Capital Power's publicly stated Sustainability Targets; to reduce Scope 1 CO_2 emission intensity by 65% by 2030 from 2005 levels. The SLCs include terms that reduce or increase borrowing costs as the annual targets are met or missed. Achievement of the Company's GHG emission intensity reductions will be driven by operational enhancements, strategic investments in renewables and decarbonization technologies, and the elimination of coal through the Genesee repowering project. Both SLCs have an expiration date of July 13, 2026). Confirmation of Guarantees from the Company, CPLP, Capital Power (US Holdings) Inc., Capital Power LP Holdings Inc. and Capital Power U.S. Financing L.P. in respect of their affiliate guarantees were provided to the lenders to ensure that any obligations of the borrowers remain pari passu with the Company's other senior unsecured borrowings. Similar guarantees were also provided for all Note Purchase Agreements and the Prudential Agreement (as defined above under "Capital Structure – Debt Issuance") to meet the pari passu covenants in those agreements.

The syndicated and club credit facilities also 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 Capital Power Corporations consolidated financial results.

Capital Power has existing Canadian dollar revolving letter of credit demand facilities with various lenders that were increased by $100 million in September 2019 and by $220 million in November 2021 (includes a new demand facility for $70 million with an additional lender). These demand facilities now total $520 million. In addition, the two U.S. dollar revolving letter of credit demand facilities that were put in place in September and November 2019 totalling $100 million were also increased by $100 million in December 2021 and now total U.S.$200 million.

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 2021 CPX Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$38.34	$34.58	$36.48	7,837,930
February	$38.10	$34.03	$34.31	6,793,477
March	$37.05	$33.31	$36.40	8,241,712
April	$39.58	$36.22	$39.19	4,572,351
May	$40.40	$37.82	$38.44	7,788,725
June	$42.28	$38.14	$40.95	8,946,267
July	$42.37	$39.99	$42.30	4,915,959
August	$43.69	$41.60	$43.39	3,819,330
September	$45.04	$42.03	$42.71	4,632,621
October	$45.05	$40.07	$40.65	5,062,310
November	$41.47	$38.04	$38.10	5,333,608
December	$40.29	$37.95	$39.46	5,376,690

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 2021 CPX.PR.A Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$12.78	$11.91	$12.27	64,424
February	$13.58	$12.12	$13.45	149,864
March	$14.46	$13.50	$14.22	211,907
April	$14.74	$14.13	$14.62	44,699
May	$15.20	$14.61	$15.18	57,115
June	$15.65	$15.12	$15.41	64,419
July	$15.50	$15.05	$15.35	20,300
August	$15.46	$15.08	$15.25	50,089
September	$16.10	$15.19	$16.00	52,264
October	$16.61	$15.86	$16.35	24,528
November	$16.90	$16.10	$16.55	47,117
December	$16.64	$15.67	$15.97	86,711

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 2021 CPX.PR.C Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$19.42	$18.45	$18.95	71,903
February	$20.58	$18.84	$20.20	109,186
March	$21.87	$20.20	$21.68	261,305
April	$22.48	$21.10	$22.48	136,302
May	$23.50	$22.40	$23.50	86,635
June	$25.00	$23.50	$24.70	274,218
July	$25.00	$23.83	$24.95	356,837
August	$24.99	$24.55	$24.90	79,322
September	$25.25	$24.41	$25.25	78,644
October	$25.35	$25.00	$25.25	77,276
November	$25.36	$24.84	$25.01	139,251
December	$25.30	$24.48	$25.01	67,474

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 2021 CPX.PR.E Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$18.87	$17.50	$18.07	142,501
February	$19.45	$18.06	$19.39	252,563
March	$21.00	$19.15	$21.00	178,020
April	$21.59	$20.81	$21.59	159,011
May	$22.69	$21.60	$22.55	133,617
June	$24.20	$22.54	$23.91	343,911
July	$24.88	$23.37	$23.86	399,556
August	$23.94	$23.00	$23.84	135,011
September	$24.20	$23.23	$24.20	104,114
October	$24.99	$24.00	$24.99	105,682
November	$24.96	$24.52	$24.63	99,227
December	$24.90	$24.23	$24.64	89,296

The Company's Series 7 Shares began trading on the Toronto Stock Exchange on October 4, 2016 under the symbol of CPX.PR.G. On December 31, 2021, all of the Series 7 Shares were redeemed. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2021 CPX.PR.G Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$25.55	$25.06	$25.43	233,049
February	$25.55	$25.27	$25.38	71,621
March	$25.73	$25.18	$25.50	135,515
April	$25.50	$25.31	$25.50	72,925
May	$25.92	$25.50	$25.86	191,204
June	$26.22	$25.37	$25.55	105,385
July	$25.75	$25.37	$25.71	61,694
August	$25.85	$25.50	$25.65	69,479
September	$26.19	$25.14	$25.30	159,957
October	$25.53	$25.14	$25.53	264,894
November	$25.63	$25.32	$25.33	443,708
December	$25.37	$24.98	$25.00	240,699

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 2021 CPX.PR.I Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	$25.88	$25.06	$25.33	46,429
February	$25.59	$25.24	$25.42	53,365
March	$25.72	$25.08	$25.51	107,587
April	$25.70	$25.12	$25.65	43,142
May	$26.17	$25.40	$26.17	40,240
June	$26.10	$25.32	$25.80	29,593
July	$26.19	$25.41	$25.70	33,483
August	$25.94	$25.55	$25.73	53,045
September	$25.97	$25.24	$25.60	34,325
October	$26.06	$25.20	$26.01	308,776
November	$26.02	$25.75	$25.98	44,615
December	$26.10	$25.51	$25.80	78,762

The Company's Series 11 Shares began trading on the Toronto Stock Exchange on May 16, 2019 under the symbol of CPX.PR.K. The following table sets forth the reported high and low trading prices and volumes for the periods indicated:

Toronto Stock Exchange 2021 CPX.PR.K Trading Statistics

Month	**Share Price**			**Volume Traded**
	High	**Low**	**Close**	
January	$26.97	$25.27	$25.79	54,502
February	$26.13	$25.55	$25.87	82,553
March	$26.35	$25.54	$25.70	87,607
April	$26.25	$25.41	$26.25	48,073
May	$26.40	$26.00	$26.35	52,441
June	$26.60	$26.00	$26.35	101,091
July	$26.60	$26.23	$26.60	53,930
August	$26.77	$26.38	$26.60	69,954
September	$26.77	$25.96	$26.15	88,170
October	$26.70	$26.11	$26.51	32,881
November	$26.50	$26.10	$26.10	42,184
December	$26.25	$25.66	$25.91	47,593

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, 2021:

Name, Province / State and Country of Residence	**Director Since**	**Office Held**[(1)(2)] **Committee Membership**[(3)]	**Principal Occupation During Past Five Years**
Doyle Beneby West Palm Beach, Florida, USA Date of Birth: October 1959 Shares held:[(4)] Nil	April 27, 2012	Director **Committees**: HSE PCG	Chief Executive Officer of Midland Cogeneration Venture from November 2018; prior thereto professional director from May 31, 2016
Jill Gardiner Vancouver, BC, Canada Date of Birth: December 1958 Shares held:[(4)] Common Shares – 9,156	May 25, 2015	Director and Chair **Committees**: [(5)(6)] Audit PCG HSE	Professional director.
Kelly Huntington Indianapolis, Indiana, USA Date of Birth: September 1975 Shares held:[(4)] Nil	June 3, 2015	Director **Committees**: PCG (Chair) Audit	Professional director from January 7, 2022; prior thereto Senior Vice President and Chief Financial Officer, USIC, LLC, from November 2019; prior thereto Senior Vice President of Enterprise Strategy, OneAmerica Financial Partners, Inc., from July 2015
Barry Perry St John's, NL, Canada Date of Birth: September 1964 Shares held:[(4)] 16,000	March 1, 2021	Director **Committees:** Audit PCG	Professional director from January 2021; prior thereto President and Chief Executive Officer of Fortis Inc. from January 2015
Jane Peverett West Vancouver, BC, Canada Date of Birth: September 1958 Shares held:[(4)]	March 1, 2019	Director **Committees:** PCG HSE	Professional director.

Name, Province / State and Country of Residence	Director Since	Office Held(1)(2) Committee Membership(3)	Principal Occupation During Past Five Years
Nil			
Robert L. Phillips Anmore, BC, Canada Date of Birth: January 1951 Shares held:(4) Common Shares – 5,275	April 26, 2019	Director **Committees:** Audit HSE	President of R.L. Phillips Investments Inc., a private investment firm since 2001.
Katharine B. Stevenson Toronto, Ontario, Canada Date of Birth: June 1962 Shares held:(4) Common Shares – 8,000	April 3, 2017	Director **Committees**: Audit (Chair) PCG	Professional director.
Keith Trent Charlotte, North Carolina, USA Date of Birth: October 1959 Shares held:(4) Nil	April 3, 2017	Director **Committees**: Audit HSE (Chair)	Professional director from July 2015 and President of BK Trent LLC from January 1, 2016
Brian Vaasjo Edmonton, Alberta, Canada Date of Birth: August 1955 Shares held:(4) Common Shares – 152,456	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) PCG Committee; and (iii) HSE Committee.
(4) Represents, as of December 31, 2021, the number of Common Shares, Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 9 Shares, and Series 11 Shares as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.
(5) As Chair, Jill Gardiner attends committee meetings in an ex-officio, non-voting capacity.
(6) Jill Gardiner was appointed Chair at the 2021 annual general meeting.

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, 2021(2):

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 – 152,456	May 1, 2009	President and Chief Executive Officer, Director	President and Chief Executive Officer, Capital Power Corporation from July 2009
Sandra Haskins Edmonton, Alberta, Canada Date of Birth: December 1959 Shares held:[1] Common Shares – 7,114	July 30, 2020	Senior Vice President. Finance and Chief Financial Officer from July 30, 2020; prior thereto Vice President and Treasurer from February 16, 2018 to July 30, 2020; prior thereto Vice President Forecasting and Analytics from June 30, 2013	Senior Vice President, Finance and Chief Financial Officer from July 30, 2020; prior thereto Vice President and Treasurer from February 16, 2018; prior thereto Vice President Forecasting and Analytics from June 30, 2013
Bryan DeNeve Edmonton, Alberta, Canada Date of Birth: July 1965 Shares held:[1] Common Shares – 48,896	January 4, 2011	Senior Vice President, Operations from June 1, 2021; prior thereto Senior Vice President, Business Development and Commercial Services from July 30, 2020; prior thereto Senior Vice President, Finance and Chief Financial Officer from May 1, 2015	Senior Vice President, Operations from June 1, 2021; prior thereto Senior Vice President, Business Development and Commercial Services from July 29, 2020; prior thereto Senior Vice President, Finance and Chief Financial Officer, Capital Power Corporation from May 1, 2015
B. Kathryn Chisholm, Q.C. Edmonton, Alberta, Canada Date of Birth: May 1963 Shares held:[1] Common Shares – 27,207	May 1, 2009	Senior Vice President, Planning, External Relations and Chief Sustainability Officer from July 30, 2020; prior thereto Senior Vice President, Chief Legal and Sustainability Officer from July 27, 2018; prior thereto Senior Vice President, Chief Legal and Sustainability Officer and Corporate	Senior Vice President, Planning, External Relations and Chief Sustainability Officer from July 30, 2020; prior thereto Senior Vice President, Chief Legal and Sustainability Officer from 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**
		Secretary from April 5, 2018; prior thereto Senior Vice President, Legal and External Relations and Corporate Secretary, from November 2012;	
Chris Kopecky Medford, Massachusetts, USA Date of Birth: June 1972 Shares held:(1) Common Shares – Nil(3)	July 30, 2020	Senior Vice President and Chief Legal, Development and Commercial Officer from June 1, 2021; prior thereto Senior Vice President, Chief Legal Officer from July 30, 2020; prior thereto Vice President, Business Development and Commercial from June 10, 2014	Senior Vice President and Chief Legal, Development and Commercial Officer from June 1, 2021; prior thereto Senior Vice President, Chief Legal Officer from July 30, 2020; prior thereto Vice President, Business Development and Commercial, Capital Power Corporation from June 10, 2014
Steve Owens Stony Plain, Alberta, Canada Date of Birth: April 1964 Shares held:(1) Common Shares – 4,377	June 1, 2021	Senior Vice President, Construction and Engineering from June 1, 2021; prior thereto Vice President, Construction, Capital Power Corporation from April 23, 2013	Senior Vice President, Construction and Engineering from June 1, 2021; prior thereto Vice President, Construction, Capital Power Corporation from April 23, 2013
Jacquelyn Pylypiuk St. Albert, Alberta, Canada Date of Birth: February 1969 Shares held:(1) Common Shares – 9,000	April 2015	Senior Vice President, People, Culture and Technology from July 30, 2020; prior thereto Vice President, Human Resources from April 2015	Senior Vice President, People, Culture and Technology from July 30, 2020; prior thereto Vice President, Human Resources, Capital Power Corporation, from April 2015

Notes:

(1) Represents as of December 31, 2021 the number of Common Shares, Series 1 Shares, Series 3 Shares, Series 5 Shares, Series 9 Shares, and Series 11 Shares, as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.
(2) See also "Company History – 2020 – Executive Appointments".
(3) Chris Kopecky was appointed to the executive on July 30, 2020 and has until July 30, 2025 to reach his share ownership guideline (SOG). As he is currently a resident of the United States, his ability to acquire Capital Power shares has been limited. Until his forthcoming change of residency to Canada, he will increase his ownership value by the restricted share units granted to him as part of his long-term incentive and by electing to transfer his annual incentive into deferred share units.

As at December 31, 2021, 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, 38,431 Common Shares

($39.46 per share as at the close of trading on December 31, 2021 for a value of $1,516,487), which is less than 1% of the issued and outstanding Common Shares.

As at December 31, 2021, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 287,481 Common Shares ($39.46 per share as at the close of trading on December 31, 2021 for a value of $11,344,000), which is less than 1% of the issued and outstanding Common Shares of the Company. The information as to the beneficial ownership of the Common 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, 2021, 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.

Jane Peverett was a director of Postmedia Network Canada Corp. (Postmedia) between April 2013 and January 2016. On October 5, 2016, Postmedia completed a recapitalization transaction pursuant to a court approved plan of arrangement under the Canada Business Corporations Act under which, approximately US $268.6 million of debt was exchanged for shares that represented approximately 98% of the outstanding shares at that time. Additionally, Postmedia repaid, extended and amended the terms of outstanding debt obligations pursuant to the recapitalization transaction.

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.

Robert Phillips is a director of West Fraser Timber Co. Ltd. ("West Fraser"). West Fraser, together with Capital Power, is a member of the PPA syndicate that is involved in the various disputes regarding the Milner Line Loss Litigation.

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 has participated 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 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. Implementation activities by the AESO were held over the course of 2018 and 2019 and most of 2020.

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. The Court of Appeal subsequently issued a decision on June 3, 2019 denying the applications that seek, among other things, to challenge the aspect of the AUC's 2017 decision that establishes the recipient of adjustment invoices.

On December 3, 2019 the AESO filed an application with the AUC seeking to have the AUC review and vary its December 2017 decision regarding the invoicing process for the historic line loss adjustments. In its December 2017 decision, the AUC had determined that the AESO implement a single settlement process for invoicing for the entire historic period of January 1, 2006 to December 31, 2016. In its review and variance application, the AESO requested that among other things, the AUC permit the AESO to implement "pay-as-you-go" settlement of line loss adjustment invoices on a year by year basis as the AESO completed its recalculations for each year, starting with 2006.

On January 10, 2020, the AUC issued a process letter to all interested parties pursuant to which all written submissions of interested parties and the AESO would be completed by February 21, 2020. Capital Power filed submissions opposing the AESO's requested relief.

On July 9, 2020, the AUC rendered its decision directing the AESO to issue three separate invoices for the various historic years instead of a single invoice for the entire period. The AESO's invoicing compliance plan was subsequently approved in September, 2020.

On October 22, 2020 the AESO issued the first invoices covering the years 2014-2016, and payment for the related amounts occurred at the end of 2020. Concurrently, the amounts invoiced to Capital Power but not attributable to the Company were invoiced to the appropriate parties for recovery.

The AESO has completed the primary invoicing process for all three tranches of invoices covering the years 2006-2016 which were paid by the Company in December 2020, February 2021 and May 2021, respectively. The amounts invoiced to Capital Power but not attributable to the Company have been invoiced to the appropriate parties for recovery with significant portions received by the Company in December 2020, February 2021 and May 2021. A further invoice from the AESO was received in October 2021 to address trailing amounts and correct calculation errors uncovered during the invoicing process. Based on the information currently available, these did not significantly impact the net amounts paid by the Company.

In addition, in November 2020, the AESO filed a letter with the AUC requesting guidance on the treatment of interest relating to the historic invoice amounts, and particularly whether a simple interest or compound interest should apply. On January 26, 2021 the AUC issued a decision in this proceeding ordering the use of simple interest, as reflected in invoices issued by the AESO to that date. An application seeking to rehear and overturn this decision was filed with the AUC on March 26, 2021. Capital Power actively participated in these proceedings to preserve the original finding and the AUC issued a favourable decision on June 22, 2021 denying this application. The party that sought to overturn the simple interest decision had filed an application to the Alberta Court of Appeal seeking permission to appeal the AUC decision but has since discontinued to the application.

The Balancing Pool is disputing its liability to make payment for the line loss adjustment invoices related to the Sundance C PPA, which amounts to a net potential exposure to Capital Power of approximately $25 million. The Company believes the various agreements governing the termination and transfer of the Sundance C PPA and related transmission agreements with the AESO had the effect of transferring all past liabilities for the Sundance C PPA to the Balancing Pool. Capital Power has therefore filed a statement of claim at the Alberta Court of Queen's Bench on January 11, 2021 against the Balancing Pool, the Province of Alberta and the AESO in which it is seeking, among other relief, recovery from the Balancing Pool and the Province of Alberta of all amounts Capital Power was compelled to pay to the AESO on account of the line loss adjustment invoices relating to the Sundance C PPA as well as interest and legal costs, including the portion invoiced to the Balancing Pool but not received by the Company pertaining to all tranches of invoices.

Buckthorn Wind Offtake and Hedge Agreement Litigation

During the February 9 to 20, 2021 period, extreme winter weather caused some disruptions to our wind facilities, most notably in Kansas (Bloom Wind) and Texas (Buckthorn Wind) with no significant impact on the balance of Capital Power's U.S. operations. Buckthorn Wind and Bloom Wind experienced no significant physical damage, but some turbines were temporarily forced offline. Around this time, Buckthorn Wind became aware that the counterparty for its offtake and hedge agreements had been calculating the invoices for those agreements based on an incorrect reference price, which diverged widely from the reference price in the contracts during the period of extreme weather. The two parties are currently engaged in a dispute in the U.S. District Court for the Northern District of Texas over the correct reference price. Unfavorable resolution of the dispute would result in a net exposure to the Company's revenues of approximately $19 million (US$15 million).

See "Company History – 2021 – United States power operations relating to extreme weather event".

Buckthorn Wind Personal Injury Litigation

Buckthorn Wind has been named, as one of several hundred defendants, in numerous personal-injury lawsuits relating to extreme winter weather in February 2021. The cases have been consolidated for pretrial purposes in a multi-district litigation ("MDL") proceeding captioned In re Winter Storm Uri Litigation, Master Cause No. 2021-41903 in the district court of Harris County, Texas. These lawsuits bring claims for negligence, tortious interference, private nuisance, conspiracy, and unjust enrichment, and allege that plaintiffs were harmed by defendants' alleged failure to provide power during the storm. Defendants include the ERCOT, which operates Texas's electric grid and manages Texas's deregulated power market, along with numerous ERCOT market participants, including retail electric providers, transmission providers, electricity generators, and natural gas providers. The Company believes the claims made against it in these lawsuits are without merit and will be taking all appropriate actions to defend itself.

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) and again at the April 26, 2019 annual meeting of shareholders. 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 23, 2022, the Board resolved to continue the Rights Plan. If the Rights Plan is approved at the 2022 annual meeting of shareholders of Capital Power, the Rights Plan will expire at the close of business on the date of the 2025 annual meeting of shareholders, unless extended by a further vote of the shareholders at that time. If not approved, the Rights Plan will expire at the end of the Company's 2022 annual meeting 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 facilities 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, 2018 and 2019 payments. The Company is disputing the withholding but has reduced the amounts recorded related to the compensation stream to reflect the uncertainty. 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, located at Suite 2200, 10175 – 101 Street, Edmonton, Alberta T5J 0H3. 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, 2021, the Audit Committee was composed of Katharine Stevenson (Chair), Kelly Huntington, Barry Perry, Robert Phillips and Keith Trent. As Chair of the Board, Jill Gardiner 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".

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
Katharine Stevenson	• member of public company audit committees for 12 years • 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

AC Member	Relevant Education and Experience
Kelly Huntington	• former Senior Vice President and Chief Financial Officer of USIC as of January 7, 2022 • formerly Senior Vice President of Enterprise Strategy for OneAmerica Financial Partners which included responsibility for internal audit • formerly President & Chief Executive Officer, and Senior Vice President & Chief Financial Officer for Indianapolis Power and Light 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
Barry Perry	• Certified Professional Accountant • former Chief Executive Officer of Fortis Inc. • former Chief Financial Officer of Fortis Inc. • holds a Bachelor of Commerce from Memorial University of Newfoundland
Robert Phillips	• acquired significant experience and exposure to accounting and financial reporting issues as the current President of R.L. Phillips Investments Inc., a private investment firm • formerly President and Chief Executive Officer of the BCR Group of Companies, PTI Group Inc, and Dreco Energy Services Ltd. • formerly Executive Vice President of MacMillan Bloedel Limited • current Chair and member of the Audit Committee of Canadian Western Bank • current director and chair of the Audit, Finance and Risk Committee of Canadian National Railway Company • former director of Maxar Technologies Inc. and member of its Audit Committee • former director and Chair of Precision Drilling Corporation and member of its Audit Committee • fellow and director of the Institute of Corporate Directors and Chair of its Audit Committee
Keith Trent	• former General Counsel for Duke Energy overseeing the internal audit team • previous profit/loss accountability for four of Duke Energy's electric utilities and for its commercial generation business • former Chair of Duke Energy's Transaction and Risk Committee which provided financial and risk analysis for numerous transactions • current director and member of the Audit Committee of Edison International • former director and member of the Audit Committee of TRC, Inc.

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 2021, the Chair of the Audit Committee pre-approved non-audit related services in an amount not to exceed $5,000 with respect to follow up work regarding cross border financing structures. This pre-approval was ratified by the Audit Committee at the next quarterly meeting. In 2021, the committee also pre-approved non-audit related services in an amount not to exceed $25,000CAD with respect to penetration testing on the Corporation's information systems and operational technology networks.

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, 2021 in respect of the Company and the Company's subsidiaries were approximately $1.5 million as detailed below.

	Twelve Months Ended December 31, 2021 ($ Millions)	**Twelve Months Ended December 31, 2020 ($ Millions)**
Audit fees	0.9	1.0
Audit related fees	0.1	0.1
Tax fees	-	-
All other fees	0.5	0.6
Total	**1.5**	**1.7**

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.

Other Committees

Apart from the Audit Committee, the Board has established: (i) the PCG Committee to oversee matters relating to corporate governance, nomination, compensation and human capital; 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. Jill Gardiner, the Chair of the Board, is a non-voting ex-officio member of all committees. The members of these committees as at December 31, 2021 were as follows:

PCG Committee

Kelly Huntington, Chair
Doyle Beneby
Barry Perry
Jane Peverett
Katharine Stevenson
Jill Gardiner (ex-officio)

Health, Safety and Environment Committee

Keith Trent, Chair
Doyle Beneby
Jane Peverett
Robert Phillips
Jill Gardiner (ex-officio)

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 Integrated Annual Report for the year ended December 31, 2021.

The "Risks and Risk Management" section of the Company's Integrated Annual Report for the year ended December 31, 2021 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.

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 the President and Chief Executive Officer (the CEO) and their management team (Management) (including fraud risk assessment) and the programs established by the CEO and 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. The CEO and Management are 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 the CEO and 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, the CEO, 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 of the Corporation (Directors) as may be specified by the Board from time to time, which number will be not less than three (the Committee Members).

2. The Chair of the Board (the Chair) is an ex-officio and non-voting member of the Committee, unless appointed by the Board as a Committee Member.

3. At least once every calendar year, and as otherwise may be required,Committee Members and the chair of the Committee (the Committee Chair) will be appointed by the Board on the recommendation of the People, Culture, and Governance Committee (the PCG Committee).

4. 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, National Instrument 52-110 *Audit Committees* or "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.

5. 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.

6. All members of the Board will be free to attend and participate at any meetings of the Committee, but only Committee Members will be entitled to vote on any question before the Committee. Other than members of the Board, entitlement to attend all or a portion of any Committee meeting will be determined by the Committee Chair or Committee Members

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 the CEO and 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 Corporation's chief financial officer (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. This is achieved through annual reviews of the external auditors, with a comprehensive review conducted every 5 years. Annual reviews include evaluation of the external auditors based on audit quality indicators including metrics for fee competitiveness, involvement of partners/managers in the Corporation's audits, audit team turnover, use of topical specialists in the audit, and audit file inspection results by internal or external regulators.

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 the CEO and 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 charter, staffing, scope and objectives of the internal audit department, and the appointment, termination, and compensation of the chief audit person (Senior Manager, Internal Audit) 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 Senior Vice President, Planning, External Relations and Chief Sustainability Officer 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 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 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 PCG Committee for further recommendation to the Board.

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

40. The Committee Chair, as well as a member of Management independent from Internal Audit, will pre-approve the project scope of audits of areas which directly report to the Senior Manager, Internal Audit.

41. Report to the Board as required.

D. Meetings

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

2. 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. A majority of Committee Members will constitute a quorum. The Committee Chair will be a voting member and questions will be decided by a majority of votes.

3. 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.

4. Meetings are chaired by the Committee Chair or in the Committee Chair's absence, by a Committee Member chosen from among and by Committee Members present at the meeting.

5. At each meeting, an in camera session will be held with just the Committee members in attendance.

6. Agendas will be set by the Committee Chair with such assistance as the Committee Chair may request from the CEO, General Counsel, 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 and Board Members and, if directed by the Committee Chair, to the CEO, the General Counsel, Corporate Secretary, 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 Committee Members by telephone, video, or other virtual meeting techniques which permits all persons participating in the meeting to hear and

communicate with each other. A Committee Member participating in a meeting by those 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, as applicable, 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, the auditors and others will be determined by the Committee and will normally include the CEO, CFO, the Corporate Secretary and appropriate staff.

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. 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.