Annual Information Form

Capital Power Corporation

For the year ended December 31, 2024

February 25, 2025

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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, 2024. 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 the non-GAAP financial measures, 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 standardized financial measures according to GAAP and do not have standardized meanings prescribed by GAAP. For further discussion of such terms, see the Company's 2024 Integrated Annual Report for the year ended December 31, 2024.

The "Non-GAAP Financial Measures and Ratios" and "Risks and Risk Management" of the Company's 2024 Integrated Annual Report for the year ended December 31, 2024 are incorporated herein by reference and can be found on SEDAR+ at www.sedarplus.ca.

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.

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 and costs of, generation capacity of, costs of technologies selected for, environmental and sustainability benefits, commercial and partnership arrangements regarding existing, planned and potential development projects and acquisitions (including phase 2 of Halkirk Wind, the upgrade at Goreway and York Energy, Goreway Battery Energy Storage System (BESS), York Energy BESS, East Windsor expansion, Maple Leaf Solar, Hornet Solar and Bear Branch Solar project; (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 the feasibility of developing and advancing nuclear energy in Alberta, including the expected capital costs, project returns, production and environmental benefits; (v) expectations regarding availability of fuel supply; (vi) expectations regarding the timing or outcome of applications for permits or licenses, or other regulatory proceedings; (vii) the expected impact of the GHG Regulations, the Federal Plan, Canada's NDC, Clean Electricity Regulations, Emissions Reduction Plan, and other regulations announced by the Government of Canada, provinces, the US including the US EPA and US states, and other environmental regulations on Capital Power's power facilities, including compliance costs and the useful lives of power facilities and any conversions, and the anticipated impact of the Alberta Sovereignty Act; (viii) 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; (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) expectations regarding changes to existing EPA rules by U.S. federal government and the resulting impact on Capital Power’s federal regulatory compliance requirements; (xii) the timing, imposition and impact of taxes on Capital Power; (xiii) the impact and cost of the discontinuation of the Genesee CCS project; (xiv) the timing, expected proceeds and benefits of selling interests in renewable power assets; (xv) expectations related to Capital Power's future cash requirements including interest and principal repayments, capital expenditures and dividends and distributions; (xvi) expectations governing the operation of the dividend reinvestment plan for holders of Common Shares; (xvii) expectations regarding the ability of profit sharing arrangements to support partner communities; (xviii) the impact, cost and benefits of any organizational reviews (including the expected operational efficiency resulting from the Voluntary Departure Program); (xix) expectations for Capital Power's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings; (xx) expectations regarding power requirements and demand in Capital Power's target markets; (xxi) 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; (xxii) expectations regarding Capital Power's intention to acquire Common Shares pursuant to its normal course issuer bid; (xxiii) the timing, expected capital costs, project returns, production and environmental benefits (including the expected reduction in emission levels) of gas conversion at the Genesee units; (xxix) expectations regarding the eligibility of certain projects for the Clean Technology ITC; (xxx) expectations relating to changes to existing IRA provisions to be made by U.S. federal government and the resulting impact on tax credit benefits for Capital Power’s renewable projects; and (xxxi) expectation regarding the outcome of the ongoing litigation in respect of the Genesee Repowering Project.

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, and 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; and (vii) foreign exchange rates; and other matters discussed under the "Our Strategy" section in the Company's 2024 Integrated Annual Report pertaining to Performance Targets for 2024.

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, including inflation and recession; (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 2024 Integrated Annual Report for the year ended December 31, 2024.

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"

"**AAQOs**" means Ambient Air Quality Objectives

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

"**AEPA**" means Alberta Environment and Protected Area

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

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

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

"**AIF**" means Annual Information Form

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

"**AMIL. BGS6 Load Zone**" means the Ameren Illinois Basic Generation Service 6 Load Zone

"**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

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

"**BESS**" means battery energy storage system

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

"**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 Wind"

"**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*

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

"**CCUS**" means carbon capture, utilization and storage

"**CERs**" means Clean Electricity Regulations

"**CES**" means the Clean Energy Standard

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

"**Clydesdale Solar**" means the Clydesdale solar project (formerly Enchant Solar) as further described in "Business of Capital Power – Western Canada Contracted Facilities – Clydesdale Solar"

"**CO_2**" means carbon dioxide

"**CO_2e**" means carbon dioxide equivalent

“COD” means commercial operation date

"**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

"**COP28**" means the 28th United Nations Climate Change Conference

"**COP29**" means the 29th United Nations Climate Change Conference

"**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 NO_x 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"

"**Draft CER**" means Draft Clean Electricity Regulations

"**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"

"East Windsor Expansion" means the East Windsor Expansion project as further described in "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – East Windsor Generation Facility Expansion"

"**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

"E-LT1" means the Ontario's IESO Expedited Long-Term Procurement Process

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

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

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

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

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

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

"**EPEA**" means the *Environmental Protection and Enhancement Act,* RSA 2000, c E-12

"**EPS**" mean emissions performance standards

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

"**ERP**" means the Emissions Reduction Plan of Canada

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

"**FEED**" means front-end engineering and design

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

"**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

"**Frederickson**" means the Frederickson 1 facility as further described in "Business of Capital Power - US Contracted Facilities – Frederickson 1"

"**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 CCS Project**" means the Genesee carbon capture and storage project as further described in "Company History – 2024 – Discontinuation of $2.4 billion Genesee CCS project"

"**Genesee Generating Station**" means, collectively, Genesee 1 and 2 and Genesee 3

"**Genesee Mine**" means the surface strip mine located near Warburg, Alberta

"**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"

"**Goreway BESS**" means the Goreway Battery Energy Storage System as further described in "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – Goreway Battery Energy Storage System"

"**Goreway Uprate Project**" means the Goreway turbine efficiency as further described in "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – Goreway Power Station – Upgrade Project"

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

"**Green Financing**" means green bonds and green loans issued under the Green Framework as further described in "Company History – 2022 – Green Financing Framework"

"**Green Framework**" means the Green Financing Framework as further described in "Company History – 2022 – Green Financing Framework"

"**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"

"**Harquahala**" means the Harquahala Facility as further described in "Business of Capital Power- US Contracted Facilities – Harquahala"

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

"**HRCO**" means heat rate call option

"**HSSE**" means health, safety, security and environment (formerly health, safety and environment)

"HSSE Management System" means the Health, Safety, Security and Environment Management System of the Company

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

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

"**Integrated Annual Report**" means the Company's 2024 Integrated Annual Report

"**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

"**IRP**" means Integrated Resource Plan

"**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

"**ITC**" means Investment Tax Credit

"**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"

"**La Paloma**" means the La Paloma Facility as further described in "Business of Capital Power- US Contracted Facilities – La Paloma"

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

"**LNG**" means liquified natural gas

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

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

"**Midland Cogen**" means the Midland Cogeneration Venture as further described in "Business of Capital Power – US Contracted Facilities – Midland Cogeneration"

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

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

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

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

"**MSSC**" means Most Severe Single Contingency

"**Mt**" means metric ton

"**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"

"**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

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

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

"**Prudential Notes**" means 10-year Series C Senior Notes with Prudential Capital Group that mature in September 2026

"**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

"**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 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.

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

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

"**RTO**" means Regional Transmission Organization

"**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 Data Analysis and Retrieval, which can be accessed via the internet at www.sedarplus.ca

"**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 of the Company and redeemed on December 31, 2021

"**Series 9 Shares**" means the cumulative minimum rate reset preference shares, series 9 of the Company and redeemed on September 30, 2022

"**Series 11 Shares**" means the cumulative minimum rate reset preference shares, series 11 of the Company and redeemed on June 30, 2024

"**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 – Western Canada Contracted Facilities – Strathmore Solar"

"**Subordinated Notes**" means the Fixed-to-Fixed Subordinated Notes, Series 1, due September 9, 2082 issued by the Company

"**tCO_2e**" means metric tonnes of carbon dioxide equivalent

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

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

"**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

"**VPPA**" means Virtual Power Purchase Agreement

"**Water Frameworks**" means the consultation process to develop new surface water quality management frameworks for the North Saskatchewan, Battle and Upper Athabasca rivers

"**WEIM**" means the Western Energy Imbalance Market, which is a real-time energy market established to manage variations in demand and generation across a wider footprint including DSW, CAISO and the Pacific Northwest

"**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"

"**York BESS**" means the York Battery Energy Storage System as further described in "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – York Battery Energy Storage System"

"**York Uprate Project"** means the York turbine efficiency as further described in "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – York Energy Centre – Upgrade Project"

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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, May 9, 2019, and September 7, 2022 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, 2024, had aggregate total assets or revenues that did not exceed 20% of Capital Power's consolidated assets or consolidated revenue. 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
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
Capital Power Investments LLC	Delaware
Whitla 2 Wind Generation L.P.	Alberta
CXA La Paloma, LLC	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

As a growth-oriented power producer, Capital Power prioritizes the safe delivery of reliable and affordable power communities can depend on, building lower-carbon power systems, and creating balanced energy solutions. As a group of experts and innovators in its field, Capital Power works to deliver responsible power for communities across Canada and the U.S. through the development, acquisition, ownership and safe operation of renewable and thermal power generation facilities. Currently, Capital Power owns approximately 10 GW of power generation at 30 facilities. 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

2024

Renewable Power Asset Sell-Down

On December 20, 2024, the Company announced the closing of the previously announced sale of a 49% interest in each of the Quality Wind facility in British Columbia and the Port Dover and Nanticoke Wind facility in Ontario.

On November 26, 2024, Capital Power previously announced that it agreed to sell a 49% interest in two operating Canadian wind facilities to Axium Infrastructure Inc. The 246 MW portfolio includes the Quality Wind facility in British Columbia and the Port Dover and Nanticoke Wind facility in Ontario. Total pre-tax cash proceeds to Capital Power from the transaction are expected to be approximately $340 million, inclusive of working capital.

The two wind facilities are fully contracted with investment grade counterparties and have a remaining weighted average contract life of approximately 11 years. Capital Power will continue to manage and operate the assets on behalf of the newly formed partnership under a long-term asset management agreement.

$460 million bought offering of common shares

On December 17, 2024, the Company completed a public offering of 7,820,000 common shares (inclusive of the full exercise of a 1,020,000 common shares over-allotment option), at an issue price of $58.80 per common share for total gross proceeds of approximately $460 million (the Offering) less issue costs of $18 million.

The Company intends to use the net proceeds from the Offering to fund future potential acquisitions and growth opportunities and for general corporate purposes.

Genesee Repowering Achieves Commercial Operation

On December 13, 2024, Unit 2 achieved combined cycle commercial operations. This milestone marked a significant phase in the Genesee Repowering project, resulting in Units 1 and 2 becoming Canada’s most efficient natural gas combined cycle facility. The advancement of this industry-leading project increases overall capacity at the Genesee Generating Station by 512 megawatts (MW) and reduces CO_2 emissions (scope 1) by 3.4 million tonnes annually – representing a ~60% increase in capacity while reducing emissions (scope 1) by ~40%.

Voluntary Departure Program

On October 24, 2024, Capital Power announced the rollout of the voluntary departure program (VDP) aimed to reduce its workforce of Canada-based corporate employees by at least 25% (approximately 130 positions). The VDP is the result of a strategic organizational review to optimize the organization to scale and grow efficiently, inclusive of decentralizing corporate functions, reducing headcount in certain areas and expanding in key growth areas.

The Company achieved a reduction in Canada-based corporate workforce of approximately 40% (165 positions) incurring a total cost of $49 million in connection with the VDP. This includes $10 million related to employee benefit costs that would have been otherwise incurred in future periods. The Company believes this initiative will enhance operational efficiency, aligns the workforce with the organization's strategic objectives and in respect to employees, provides them a choice in the change process.

$600 million medium term notes offering

On September 16, 2024, Capital Power announced that it had completed a previously announced public offering in Canada of unsecured medium-term notes in the aggregate principal amount of $600 million. The offering consisted of $600 million of 4,831% medium term notes maturing on September 16, 2031. The offering closed on September 16, 2024. Capital Power used the net proceeds to repay, redeem and refinance existing indebtedness, including indebtedness under Capital Power's credit facilities, and for general corporate purposes.

See also "Capital Structure – Debt Issuance".

$350 million Green Hybrid Subordinated Notes, Series 1 exchange

On August 15, 2024, the Company announced the approval of amendments to the indenture governing the $350 million 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 1, due September 9, 2082 (Series 1 Notes). These changes allowed for the exchange of all outstanding principal amount of Series 1 Notes for an equal principal amount of new 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 3, due September 9, 2082 (Series 3 Notes).

The Series 3 Notes have the same economic terms as the Series 1 Notes, including interest rates and maturity dates, but without the provision for delivery of preferred shares upon the occurrence of certain bankruptcy and related events. Holders will continue to receive interest accrued on the exchanged Series 1 Notes.

This note exchange was completed on August 15, 2024, following the execution of the necessary supplemental indentures. The Series 3 Notes will rank equally in right of payment with the $450 million 8.125% Fixed-to-Fixed Subordinated Notes, Series 2, due June 5, 2054. S&P Global Ratings and Morningstar DBRS confirmed the instrument rating of the Series 3 Notes at BB and BB with a Stable trend, respectively.

Dividend Increase

On July 30, 2024, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $2.46 per common share to $2.61 per common share. This increased common share dividend commenced with the third quarter 2024 quarterly dividend payment on October 31, 2024 to shareholders of record at the close of business on September 30, 2024.

Partnership with Maskwacis First Nations

On July 19, 2024, the Company signed a three-year partnership and equity option agreement with the Louis Bull Tribe, Ermineskin Cree Nation, Montana First Nation and Samson Cree Nation of Maskwacis located in Alberta. Following the three-year agreement, the Company is offering the four First Nations an opportunity to acquire a combined total of 25% of Halkirk 2 Wind. As part of the Company's commitment to reconciliation, the agreement provides an equitable profit-sharing model that supports a pathway to future, long-term equity ownership in the project that can support these nations with sustainable income throughout the lifetime of its operations.

Executes 25-year contracts for Hornet Solar and Bear Branch Solar projects in North Carolina

In June 2024, the Company successfully executed 25-year power purchase agreements with Duke Energy Carolinas for the Hornet Solar and Bear Branch Solar projects located in North Carolina totalling 107.5 MW. Hornet Solar began construction in August 2024 and Bear Branch is expected to commence construction in the first half of 2025**.** Targeted commercial operations for both projects is expected in the second half of 2026.

Genesee Generating Station is off coal

On June 18, 2024, the Company reached a significant milestone for the Genesee Repowering project with the announcement that the Genesee Generating Station is off coal and 100% natural gas-fueled, resulting in the facility being off coal more than 5 years ahead of the Alberta government mandate. With cessation of coal mining, the activities at the Genesee Mine are now wholly directed to land reclamation. This is expected to continue for the next 3 to 4 years.

As part of the Genesee Repowering project, the facility completed simple cycle commissioning for Units 1 and 2 on May 3, 2024 and June 28, 2024, respectively, and Unit 3 has transitioned fully to natural gas. Unit 1 received COD on November 18, 2024 and Unit 2 received COD on December 13, 2024 for combined cycle operation achieving 466 MWs per unit. A plan is in place for each unit to further unlock additional MWs. Both units are expected to reach 566 MWs in the first half of 2025.

$450 million Subordinated Notes offering

On June 5, 2024, the Company closed a public offering of Fixed-to-Fixed Subordinated Notes, Series 2, in the aggregate principal amount of $450 million (the Subordinated Notes). The Subordinated Notes have a fixed interest rate of 8.125% and mature on June 5, 2054.

The Company used the net proceeds from the sale of the Subordinated Notes to repay certain amounts drawn on the Company's credit facilities (which include amounts drawn for the acquisition of a 50% interest in New Harquahala Generating Company, LLC, and a 100% interest in CXA La Paloma, LLC, and related expenses, development purposes and in respect of ongoing operations), to redeem all of the Company's outstanding Cumulative Minimum Rate Reset Preference Shares, Series 11, (the Preferred Shares, Series 11) and for general corporate purposes.

See also "Capital Structure – Debt Issuance".

Redemption of Preferred Shares, Series 11

On May 15, 2024, the Company announced its intention to redeem all of its 6 million issued and outstanding Preferred Shares, Series 11 on June 30, 2024 (Redemption Date) at a price of $25.00 per share (Redemption Price) for an aggregate total of $150 million, less any tax required to be deducted and withheld by the Company. As June 30, 2024 was not a business day payment of the Redemption Price for the share redemption occurred on July 2, 2024.

Board of Director changes

On May 15, 2024, the Company announced the appointment of Neil H. Smith and George Williams to the Company's Board of Directors effective May 15, 2024. The appointments follow Doyle Beneby's retirement, after serving the full 12 year term limit as a member of the Board of Directors. With these appointments and retirement, Capital Power's Board of Directors consists of 11 directors, with 40% of the independent directors being women, and 30% of the independent directors representing diverse groups beyond gender.

Discontinuation of $2.4 billion Genesee CCS project

On May 1, 2024, Capital Power announced that it was discontinuing its pursuit of the Genesee CCS project. Through its development of the project, Capital Power has previously confirmed CCS is a technically viable technology and potential pathway to decarbonization for thermal generation facilities including Genesee. However, at this time, the project is not economically feasible and as a result Capital Power will be turning its time, attention, and resources to other opportunities to serve its customers with balanced energy solutions. As part of its discontinuation of the project, Capital Power will incur a pre-tax cost of $18 million, related to termination of sequestration hub evaluation work.

Large-scale virtual power purchase agreement with Saputo Inc.

On March 27, 2024, the Company announced it had entered into a 15-year virtual power purchase agreement (VPPA) with Saputo Inc. The agreement pertains to the Company's Canadian-based wind facility Halkirk 2 currently under construction. Final regulatory approval was received in June 2024 and once operational, the portion of the wind facility contracted by Saputo will generate approximately 181,000 MWh of renewable electricity per year.

Completion of acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility

On February 9, 2024, the Company announced closing of the previously announced acquisition of 100% of the equity interests in CXA La Paloma, LLC (La Paloma), owner of the 1,062 MW La Paloma natural gas-fired generation facility in Kern County, California (La Paloma Acquisition). On February 16, 2024, the Company announced closing of the previously announced acquisition by a 50/50 partnership between Capital Power Investments, LLC and an affiliate of a fund managed by BlackRock's Diversified Infrastructure business (BlackRock) of 100% of the equity interests in New Harquahala Generating Company, LLC (Harquahala Acquisition and, together with the La Paloma Acquisition, the Acquisitions) which owns the 1,092 MW Harquahala natural gas-fired generation facility in Arizona. Concurrently, approximately US$442 million of combined term loans, letter of credit loans and revolving loans related to the Harquahala facility were closed as part of the transaction.

La Paloma and Harquahala are essential infrastructure assets, which support the reliability of California and Arizona's electricity grids and add further growth opportunities in the attractive Western Electricity Coordinating Council (WECC) market while balancing the Company's geographical footprint across North America. La Paloma is contracted under various resource adequacy contracts through 2029 with multiple investment grade utilities and load serving entities. Harquahala is 100% contracted under a tolling agreement through 2031 with an investment grade utility.

The Acquisitions were previously announced on November 20, 2023. The net purchase price for the Acquisitions attributable to Capital Power is US$1.1 billion, subject to working capital adjustments. Capital Power partially financed the Acquisitions with the net proceeds of an offering of subscription receipts (the Subscription Receipts) for approximately $400 million, which closed on November 28, 2023 and consisted of a $300 million bought public offering and a $100 million private placement with Alberta Investment Management Corporation. Capital Power also financed the Acquisitions with the net proceeds from a public offering of $850 million principal amount of unsecured medium term notes in Canada which closed on December 15, 2023. Capital Power will be responsible for the operation, maintenance and asset management of the facilities relating to the Acquisitions and will receive an annual management fee for the Harquahala facility.

Upon closing of the La Paloma Acquisition, each Subscription Receipt was automatically exchanged in accordance with their terms, without payment of additional consideration and without further action on the part of the holders thereof, for one common share of Capital Power.

The Acquisitions are expected to generate average annual Adjusted EBITDA of approximately $265 million (US$197 million) for the 2024-2028 period and are estimated to be, on average, 8% accretive to AFFO per share over the same period.

See also "Company History – 2023 – Announcing acquisitions of two contracted combined cycle U.S. gas generation facilities and concurrent equity offerings" and "General Development of the Business – Company History" and "Capital Structure – Common Shares – Subscription Receipts".

Partnered with Ontario Power Generation to advance new nuclear in Alberta

On January 15, 2024, the Company announced that it had entered into an agreement with Ontario Power Generation (OPG) to jointly assess the development and deployment of grid-scale small modular reactors (SMRs) to provide clean, reliable nuclear energy for Alberta.

Pursuant to the agreement, the two companies will examine the feasibility of developing SMRs in Alberta, including possible ownership and operating structures. SMRs are being pursued by jurisdictions in Canada and around the world to power the growing demand for clean electricity and energy security.

Capital Power and OPG will complete the feasibility assessment within two years, while continuing to work on the next stages of SMR development. In 2024, Capital Power qualified for $13 million in funding to support certain activities to be undertaken as part of the feasibility assessment.

<u>2023</u>

Acquisition of 50.15% interest in Frederickson 1 Generating Station

On December 28, 2023, Capital Power successfully completed the previously announced acquisition of a 50.15% ownership interest in the Frederickson 1 Generating Station, a 265 MW natural gas-fired combined cycle generation facility located in Pierce County, Washington. The facility was acquired from Atlantic Power & Utilities for $137 million (US$100 million) of cash consideration, including working capital and other closing adjustments. The other 49.85% is owned by Puget Sound Energy. Capital Power financed the acquisition using cash on hand and our existing credit facilities.

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

$850 million medium term notes offering

On December 15, 2023, Capital Power announced that it had completed a previously announced public offering in Canada of unsecured medium term notes in the aggregate principal amount of $850 million. The offering consisted of $400 million of 5.378% medium term notes maturing on January 25, 2027 and $450 million of 5.973% medium term notes maturing on January 25, 2034. The offering closed on December 15, 2023.

See also "Capital Structure – Debt Issuance".

Announcing acquisitions of two contracted combined cycle U.S. gas generation facilities and concurrent equity offerings

On November 20, 2023, Capital Power announced that it had entered into two separate definitive agreements with CSG Investments Inc., a subsidiary of Beal Financial Corporation, to acquire (i) 100% of the equity interest in CXA La Paloma, LLC which owns the 1,062 MW La Paloma natural gas fired generation facility in Kern County, California (La Paloma Acquisition); and (ii) under a new formed 50/50 partnership with an affiliate of BlackRock's Diversified Infrastructure business, 100% of the equity interest in New Harquahala Generation Company, LLC which owns the 1,092 MW natural gas-fired generation facility in Maricopa County, Arizona (Harquahala Acquisition and together with the La Paloma Acquisition, the Acquisitions).

Concurrent with the announcement of the Acquisitions, Capital Power announced it had entered into an agreement with a syndicate of underwriters to issue 8,231,000 subscription receipts, on a bought deal basis, at an issue price of $36.45 per subscription receipt, for total gross proceeds of approximately $300 million. Additionally, Capital Power entered into a subscription agreement to issue 2,745,000 subscription receipts to Alberta Investment Management Corporation on a private placement basis for gross proceeds of approximately $100 million. The concurrent equity offering closed on November 28, 2023.

See also "Capital Structure – Common Shares – Subscription Receipts".

See also "Completion of acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility" and "Business of Capital Power - US Contracted Facilities – Harquahala" and "Business of Capital Power – US Contracted Facilities – La Paloma".

Executive Appointments

On August 29, 2023, Capital Power and the Board of Directors announced the following executive position appointments:

- Steve Wollin, Senior Vice President, Operations;
- Bryan DeNeve[(1)], Senior Vice President, Chief Commercial Officer;
- May Wong, Senior Vice President, Strategy, Planning & Sustainability;
- Pauline McLean, Senior Vice President, External Relations and Chief Legal Officer; and
- Jason Comandante, Senior Vice President, Head of Canada.

Sandra Haskins and Jacquie Pylypiuk continued to serve in their current roles as Senior Vice President, Finance and Chief Financial Officer; and Senior Vice President, Technology and Chief People and Culture Officer, respectively.

Note:
(1) Bryan DeNeve served as Senior Vice President, Chief Commercial Officer, until January 19, 2025.

Reinstatement of Dividend Reinvestment Plan

On August 1, 2023, the Company reinstated the DRIP. Eligible shareholders were entitled to participate in the DRIP commencing with the Company's third quarter 2023 cash dividend. Shareholders that were enrolled in the DRIP upon suspension in December 2021, 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 1% to the average closing price on the Toronto Stock Exchange for the 10 trading days immediately preceding the applicable dividend payment date.

Secured 1 gigawatt supply of solar modules

On July 5, 2023, Capital Power announced that it had secured its first order for approximately 1 gigawatt of responsibly produced, ultra-low carbon thin firm solar modules. The modules, which will be delivered between 2026 and 2028, will support Capital Power's growing development portfolio.

Contracts executed for Natural Gas and Batteries from Ontario's IESO bids

On June 29, 2023, Capital Power announced that it had executed two long-term contracts for the East Windsor Expansion project and the York BESS project. The York BESS project is expected to achieve commercial operation in 2025 while the East Windsor Expansion project has been updated to begin commercial operations in 2026 due to delays in municipal and provincial permitting processes. In addition, Capital Power was selected as a successful proponent for the Goreway Battery Energy Storage System project as part of Category 2 of the IESO's Expedited Long-Term RFP.

See also "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – York Battery Energy Storage System" and "Business of Capital Power - Projects Under Construction or in Advanced Stages of Development – East Windsor Generation Facility Expansion".

Maple Leaf Solar project awarded 25-year contract

On June 29, 2023, Capital Power announced that it had entered into a 25-year PPA for 100% of the output from its Maple Leaf Solar project with Duke Energy Progress as part of the 2022 Duke Energy Solar Procurement Program.

See also "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – Maple Leaf Solar".

Two successful bids in Ontario IESO's Expedited Long-Term RFP

On May 16, 2023, Capital Power announced that it had been selected as a successful proponent in the Ontario IESO's Expedited Long-Term RFP. The two successful submissions included the York Battery Energy Storage System and East Windsor Generation Facility Expansion. Subsequently, on June 23, 2023, Capital Power executed long-term contracts with the IESO.

See also "Company History – 2023 – Contracts executed for Natural Gas and Batteries from Ontario's IESO bids", "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – York Battery Energy Storage System" and "Business of Capital Power – Projects Under Construction or in Advanced Stages of Development – East Windsor Generation Facility Expansion".

Executive appointments

On April 19, 2023, Capital Power and the Board of Directors announced that it had selected Avik Dey to be the new President and Chief Executive Officer and become a member of the Board of Directors, effective May 8, 2023.

Approval of normal course issuer bid

On March 1, 2023, the Toronto Stock Exchange approved the Company's normal course issuer bid to purchase and cancel up to 5.8 million of its outstanding Common Shares during the one-year period from March 3, 2023 to March 2, 2024.

23-year clean electricity supply agreement with Public Services and Procurement Canada

On February 3, 2023, Capital Power announced that it had entered into a 23-year clean electricity supply agreement with Public Services and Procurement Canada (PSPC) to meet the power needs of all federal government buildings in Alberta. Capital Power will provide approximately 250,000 MWh of clean electricity per year initially through Canada-sourced REC's until Halkirk 2 is completed, which was expected to be operational by January 1, 2025 (subject to regulatory approval) but is now expected to reach COD by March 31, 2025. Once complete, Halkirk 2 will provide renewable energy to PSPC for the remainder of the term representing approximately 49% of Halkirk 2's output.

15-year renewable energy agreement with Shaw Communications Inc.

On January 17, 2023, Capital Power announced that it had entered into a 15-year Virtual Power Purchase Agreement with Shaw Communications Inc. for the purchase of approximately 30 MW of renewable energy from the Clydesdale Solar facility. The renewable energy is bundled with 100% of the associated greenhouse gas offsets and environmental attributes generated from Shaw Communications' share of the facility's generation output.

2022

Clydesdale Solar (formerly Enchant Solar) begins commercial operations

On December 13, 2022, Clydesdale Solar began commercial operations. Formerly called Enchant Solar, this is Capital Power's second Canadian solar facility. At a total capital cost of approximately $124 million, the 75 MW facility is located on 560 acres of leased land within the municipal district of Taber, Alberta. The facility is party to a 15-year renewable energy agreement to sell 51% of the electricity generated from Clydesdale Solar to Labatt Brewing Company Ltd. along with bundled renewable energy certificates.

See also "Business of Capital Power – Western Canada Contracted Facilities – Clydesdale Solar (formerly Enchant Solar)".

Plans advance for Genesee CCS Project

On December 1, 2022, the Company's Board of Directors approved a limited notice to proceed (LNTP) for the Genesee CCS Project. The decision to proceed with LNTP was due in part to progress made by the Company on funding programs from the Alberta and federal governments such as the Alberta CCS Hub initiative, Emissions Reduction Alberta support for the FEED study, the federal CCUS investment tax credit, potential financial support from the Canada Infrastructure Bank, the Canada Growth Fund and the Strategic Innovation Fund. Subsequently, Capital Power postponed the Genesee CCS Project's final decision until it secures carbon price assurances from the government of Canada.

Genesee 3 completes 100% dual fuel capability upgrades

On November 12, 2022 Genesee 3 completed necessary modifications to operate as a 100% dual fuel natural gas and coal facility. Capital Power also ceased coal mining activity and announced it would operate Genesee 3 solely on natural gas once all remaining coal inventory has been exhausted.

Genesee 2 approved for 20MW of additional capacity

On October 1, 2022, 20MW of additional capacity at Genesee 2 was approved by the AESO. The additional capacity is a result of stator and low-pressure rotor replacements associated with the 2021 outage.

Redemption of Preferred Shares, Series 9

On September 30, 2022 Capital Power redeemed all of its 6,000,000 issued and outstanding 5.75% Series 9 Shares at a price of $25.00 per share for an aggregate total of $150 million, less any tax required to be deducted and withheld by the Company.

Acquisition of Midland Cogeneration Facility

On September 23, 2022, Capital Power and Manulife Investment Management, on behalf of the Manulife Infrastructure Fund II and its affiliates, completed the acquisition of a 100% interest in MCV Holding Company LLC through its joint venture partnership, MCV Partners LLC. MCV Holding Company LLC owns 100% of Midland Cogen, a 1,633 MW natural gas combined-cycle cogeneration facility located in Midland, Michigan supported by long term contracts through 2030 and 2035. Capital Power's investment for our 50% ownership of MCV Partners LLC was $280 million (US $208 million) of cash consideration, including preliminary working capital and other closing adjustments of $29 million (US $22 million). Capital Power financed our share of the transaction using cash on hand and our existing credit facilities.

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

$350 million Green Hybrid Subordinated Notes offering

On September 9, 2022, the Company closed a $350 million offering of Fixed-to-Fixed Subordinated Notes, Series 1, due September 9, 2082 (Subordinated Notes), the first ever green hybrid subordinated debt security in Canada. The Subordinated Notes have a fixed 7.95% interest rate, payable semi-annually, which resets on September 9, 2032, and on every fifth anniversary thereafter, based on the five-year Government of Canada yield plus: (i) 5.34% for the period from, and including, September 9, 2032 to, but excluding, September 9, 2052; and (ii) 6.09% for the period from, and including, September 9, 2052 to, but excluding September 9, 2082.

In connection with the Company's offering of the Subordinated Notes, Capital Power issued 350,000 Series 2022-A Class A Preferred Shares to Computershare Trust Company of Canada, to be held in trust as treasury shares to satisfy Capital Power's obligations under the trust indenture governing the Subordinated Notes.

See also "General Development of the Business – Company History – 2024 – $350 million Green Hybrid Subordinated Notes, Series 1 exchange" and "Capital Structure – Debt Issuance".

Green Financing Framework

On August 15, 2022, the Company released its inaugural Green Financing Framework (Green Framework) under which the Company will issue green bonds and green loans (Green Financing). The Green Framework sets out the guidelines for Capital Power's Green Financing in accordance with the Green Bond Principles 2021 issued by the International Capital Markets Association (ICMA) and the Green Loan Principles 2021 issued by the Loan Market Association and Loan Syndications and Trading Association. The Green Framework has also been designed to align with the practices, actions, and disclosures recommended in the ICMA's Climate Transition Finance Handbook 2020.

Under the Green Framework, the net proceeds from a Green Financing will be allocated or used to finance or re-finance, in part or in full, new and/or existing green investments and expenditures made by the Company that meet the Renewable Energy category, as defined in the Green Framework, and are aligned with the United Nations Sustainable Development Goals of affordable and clean energy; industry, innovation and infrastructure; and climate action.

Advancement of carbon capture project at Genesee

On June 27, 2022, the Company announced it was collaborating with Mitsubishi Heavy Industries Group and Kiewit Energy Group on a FEED study for the Genesee CCS Project advancing the commercial application of CCS technology at its Genesee Generating Station. Enbridge has completed the FEED study, which was conducted in parallel with engineering work to advance the open access carbon hub.

During Capital Power's investor presentation in September 2023, the schedule for the Genesee CCS Project was revised. Capital Power postponed the Genesee CCS Project's final decision until it secures carbon price assurances from the government of Canada.

See also "Company History – 2024 – Discontinuation of $2.4 billion Genesee CCS project".

4.5-year contract renewal for Island Generation

On May 16, 2022, Capital Power announced the execution of a 4.5-year EPA through October 2026 for its Island Generation facility with BC Hydro. Which was subsequently approved by the British Columbia Utilities Commission on November 10, 2022.

See also "Business of Capital Power – Western Canada Contracted Facilities – Island Generation".

Executed 10-year contract for Whitla Wind

On March 18, 2022, Capital Power announced the execution of a 10-year VPPA with MEGlobal Canada ULC. The term of the VPPA commenced on April 1, 2022, and provides for the purchase of approximately 126 MW of capacity and associated environmental attributes from the balance of Capital Power's phase 2 and 3 Whitla Wind facility.

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

Strathmore Solar begins commercial operations

On March 17, 2022, Strathmore Solar, Capital Power's first Canadian solar facility, began commercial operations. At a total capital cost of approximately $59 million, the 41 MW facility is located on 320 acres of leased industrial land owned by the town of Strathmore, Alberta and fully contracted with 100% of the renewable energy and associated renewable energy credits sold to TELUS Communications under a 25-year power purchase agreement.

See also "Business of Capital Power – Western Canada Contracted Facilities – Strathmore Solar".

BUSINESS OF CAPITAL POWER

Overview

Capital Power is a growth-oriented power producer. See – 2024 Integrated Annual Report, “About Us”. At the date of this AIF, Capital Power owned approximately 10 gigawatts of gross power generation capacity at 30 facilities across North America. Projects in advanced development include approximately 180 MW of renewable generation capacity in North Carolina and approximately 350 MW of natural gas and battery energy storage systems in Ontario.

As of December 31, 2024, Capital Power's power generation fleet had a capacity weighted average facility age of 16 years and is diversified across three Canadian provinces and ten states in the US.

Capital Power owns approximately 2,900 MW of operating power generation capacity in Alberta, with ownership interests in nine facilities. 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.

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".

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.

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, 2024:

Category	Facility Name and Location	Type of Generating Facility	Year Commissioned or Target Date	Net Facility Generation Capacity (MW)[(1)]	Capital Power Interest (MW)[(1)]
Alberta Commercial Facilities	Genesee Generating Station	Natural gas-fired combined cycle	Units 1 & 2 – 2024[(7)(8)] Unit 3 – 2005[(8)]	1,857	1,857
	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 Gas, 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
	Total Alberta Commercial Facilities				**2,884**
Ontario Facilities	Kingsbridge 1, Ontario	Wind turbine	2001 & 2006	39	39
	York, Ontario	Natural gas	2012	456	228
	PDN, Ontario	Wind turbine	2013	105	53.66[(6)]
	Goreway, Ontario	Natural gas	2009	875	875
	East Windsor, Ontario	Natural gas	2009	92	92
	Total Ontario Facilities[(2)]				**1287.66**
Western Canada Facilities	Whitla Wind, Alberta [(4)]	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	72.42[(6)]
	Strathmore Solar, Alberta	Solar	2022	41	41
	Clydesdale Solar (formerly Enchant Solar), Alberta	Solar	2022	75	75
	Total Western Canada Facilities[(2)]				**826.42**
US 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 Wind, Kansas	Wind turbine	2017	178	178
	Buckthorn Wind, Texas	Wind turbine	2018	101	101
	New Frontier, North Dakota	Wind turbine	2018	99	99

Category	Facility Name and Location	Type of Generating Facility	Year Commissioned or Target Date	Net Facility Generation Capacity (MW)(1)	Capital Power Interest (MW)(1)
	Cardinal Point, Illinois	Wind turbine	2020	150	150
	Midland Cogen, Michigan	Natural Gas	1990	1,633	816.5
	Frederickson 1, Washington	Natural Gas	2002	265	132.9
	La Paloma, California(5)	Natural Gas	2003	1,062	1,062
	Harquahala, Arizona(5)	Natural Gas	2004	1,092	546
	Total US Facilities(2)				**4,635.4**
Facilities Under Construction or in Advanced Stages of Development	Halkirk 2, Alberta	Wind turbine	2025	126	126
	Goreway, Ontario	Natural Gas Uprate	2025	40	40
	Goreway, Ontario	BESS	2025	50	50
	York, Ontario	BESS	2025	120	120
	York, Ontario	Natural Gas Uprate	2025	38	19
	East Windsor, Ontario	Natural Gas	2026	106	106
	Bear Branch, North Carolina	Solar	2026	34.5	34.5
	Hornet Solar, North Carolina	Solar	2026	73	73
	Maple Leaf, North Carolina	Solar	2027	73	73
	Total Under Construction or in Advanced Stages of Development(3)				**641.5**

Notes:

(1) MW listed are net capacity.

(2) Represents Capital Power's owned capacity as at the date of this AIF.

(3) Represents Capital Power's owned capacity, capacity under construction or in advanced stages of development as at the date of this AIF.

(4) 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.

(5) La Paloma was acquired on February 9, 2024. Harquahala was acquired on February 16, 2024. See also “Company History – 2024-”*Completion of acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility*”.

(6) Capital Power completed the sale of a 49% interest in the Quality Wind facility and the Port Dover and Nanticoke Wind facility to Axium Infrastructure Inc. on December 20, 2024 resulting in a reduction of Capital Power’s interest in the two facilities’ generation capacity. See also “Company History – 2024 - Renewable Power Asset Sell-Down”.

(7) Genesee Unit 1 was originally commissioned in 1994 and Genesee Unit 2 was originally commissioned in 1989. Both units were repowered and commissioned in December 2024.

(8) The generating capacities of Units 1, 2 and 3 are 666 MW, 666 MW and 525 MW, respectively. However, there is currently a system limit in place, called the Most Severe Single Contingency (MSSC), that sets the maximum amount of supply loss the Alberta grid can reliably withstand when operating in an interconnected (466 MW limit) or islanded condition (425 MW limit). This means generation from each of Units 1, 2 and 3 is currently limited to a maximum of 466 MW or 425 MW, as applicable. The Company is exploring, with the AESO, ways to enable an increase to the generating output of each facility above the MSSC.

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, 2024**	**Twelve Months Ended December 31, 2023**
Alberta commercial facilities	1,886	2,571
Western Canada contracted facilities	143[3]	152
Ontario contracted facilities[1]	378[3]	374
U.S. contracted facilities[1][2]	903	491
Corporate	19	130
Sub Total	3,329	3,718
Unrealized changes in fair value of commodity derivatives and emission credits	447	564
Total	**3,776**	**4,282**

Notes:

(1) Ontario contracted facilities does not include York and US contracted facilities does not include Midland Cogen and Harquahala as they are accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint ventures on our consolidated statements of income. (See also "Business of Capital Power – US Contracted Facilities – Midland Cogeneration" and "Business of Capital Power - US Contracted Facilities – Harquahala".)

(2) Harquahala and La Paloma were acquired on February 16, 2024 and February 9, 2024, respectively Frederickson 1 was acquired on December 28, 2023 and due to the proximity of the acquisition to December 31, 2023, revenues and other income were immaterial in 2023.

(3) Capital Power completed the sale of a 49% interest in the Quality Wind facility and the Port Dover and Nanticoke Wind facility to Axium Infrastructure Inc. on December 20, 2024 and due to the proximity of the sale to December 31, 2024, the impact on revenues and other income was immaterial. See also "Company History – 2024 - Renewable Power Asset Sell-Down".

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, 2024**	**Twelve Months Ended December 31, 2023**
Alberta commercial facilities	13,204	15,311
Western Canada contracted facilities	2,211[3]	1,851
Ontario contracted facilities	3,178[3]	2,698
U.S. contracted facilities[1][2]	19,228	12,627
Total	**37,821**	**32,487**

Notes:

(1) Frederickson 1 was acquired on December 28, 2023 and due to the proximity of the acquisition to December 31, 2023, generation was immaterial in 2023.

(2) Harquahala and La Paloma were acquired on February 16, 2024 and February 9, 2024 and as a result, the impact on generation was only realized following the dates of such acquisitions.

(3) Capital Power completed the sale of a 49% interest in the Quality Wind facility and the Port Dover and Nanticoke Wind facility to Axium Infrastructure Inc. on December 20, 2024 and due to the proximity of the sale to December 31, 2024, the impact on generation was immaterial. See also "Company History – 2024 - Renewable Power Asset Sell-Down".

Alberta Commercial Facilities

As of December 31, 2024, the Alberta commercial facilities consisted of ownership interests in eight facilities representing approximately 2,884 MW of power generation capacity. The facilities generate electricity from 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.

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 Generating Station

Genesee repowering achieves commercial operations

On December 13, 2024, the Company announced its Genesee Repowering project is now complete as Genesee Unit 2 achieved combined cycle commercial operations, resulting in Genesee Units 1 and 2 becoming Canada's most efficient natural gas combined cycle facility[1]. Using air cooled J-series natural gas combined cycle technology from Mitsubishi, the repowered units located west of Edmonton near Warburg, Alberta are capable of providing an additional 512 MW of net capacity totalling 1332 MW. Both units are 100% owned and operated by Capital Power and are located on land owned by Capital Power.

Note:

(1) Repowered Units 1 and 2 at Genesee Generating Station use Mitsubishi M501JAC turbines and Vogt heat recovery steam generators in combined cycle mode and are the most efficient combined cycle units currently operating in Canada.

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

With the repowering of Genesee 1 and 2 completed, natural gas for these repowered 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 natural gas needs for the repowered Genesee 1 and 2 and Genesee 3 units. This new natural gas pipeline also holds significant expansion potential should the gas needs at Genesee materially increase with future development.

Genesee CCS Project

On May 1, 2024, the Company announced that it is discontinuing pursuit of the Genesee CCS Project (CCS). While the Company has confirmed that CCS is a technically viable technology and potential pathway to decarbonization for thermal generation facilities including Genesee, the project is not economically feasible at this time.

Capital Power will explore CCS at Genesee and certain assets in the Company’s North American fleet in the future as economics improve.

See also "Company History – 2024 – Discontinuation of $2.4 billion Genesee CCS project", "Company History – 2022 – Advancement of carbon capture project at Genesee" and "Company History – 2022 – Plans advance for Genesee CCS Project".

Genesee 3

Genesee 3 is a 525 MW supercritical natural gas fueled facility, 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. It has clean air technologies that include fabric filters that stop 99.8% of particulate matter from reaching the atmosphere. Upon its conversion to natural gas, the heat rate of the unit was increased by 1.5% and the net output capability was increased to 480 MW.

Commercial Arrangement: Merchant Facility

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

Fuel Supply

Genesee 3 is 100% natural gas fueled. Natural gas for Genesee 3 will be provided as part of TransCanada's firm and interruptible transport services as noted in "Alberta Commercial Facilities – Genesee Generating Station – Genesee repowering achieves commercial operations – Fuel Supply".

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 TransAlta 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.

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.

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.

CCUS

Shepard was awarded approximately $3 million from the Emissions Reductions Alberta to support its Shepard Energy Centre Carbon Capture Unit FEED study. In addition, Shepard is in pursuit of potential financial support from the Strategic Innovation Fund.

Additional Alberta Facilities

Capital Power owns and operates 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 continues to operate in 2025. Capital Power has entered into a joint venture with the City of Edmonton as of January of 2023, for the design, development, and potential construction of a new renewable natural gas facility and, if constructed, will result in the decommissioning of the power generation facility.

Western Canada Contracted Facilities

Clydesdale Solar (formerly Enchant Solar)

Clydesdale 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 began commercial operation on December 13th, 2022.

Commercial Arrangement: Renewable Energy Agreement and Virtual Power Purchase Agreement (VPPA)

The Company executed a 15-year renewable energy agreement to sell 51% of the electricity generated from Clydesdale Solar to Labatt Brewing Company Ltd. of Canada, along with bundled RECs.

In addition, Capital Power entered into a 15-year VPPA with Shaw Communications Inc. for the purchase of approximately 30 MW of renewable energy from the facility. The renewable energy is bundled with 100% of the associated greenhouse gas offsets and environmental attributes generated from Shaw's share of the facility's generation output.

See also "Company History – 2022 – Clydesdale Solar (formerly Enchant Solar) begins commercial operations".

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 comprised of an additional 42 3.6 MW Vestas V136 turbines.

Commercial Arrangement: Renewable Energy Support Agreement (RESA) Swap Arrangement and Power Purchase Agreements

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.

On March 18, 2022, the Company announced a 10-year agreement starting April 1, 2022, with MEGlobal, a subsidiary of EQUATE Petrochemical Company K.S.C.C., for 126MW of capacity and the associated environmental attributes from phases 2 and 3 of Whitla Wind.

See also "Company History – 2022 – Executed 10-year contract for 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 October 2026 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 – British Columbia".

See also "Company History – 2022 – 4.5-year contract renewal for Island Generation".

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 owned by the Company and located at gas pipeline compressor station, owned by Westcoast Energy Inc., a subsidiary of Enbridge, near Savona, British Columbia which. 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. On December 20, 2024, Capital Power announced the closing of the previously announced sale of a 49% interest in Quality to Axium Infrastructure Inc. The facility is jointly owned in a 51/49 partnership with Axium Infrastructure Inc. and is operated by Capital Power.

Commercial Arrangement: Electricity Purchase Agreement

Quality has a 25-year EPA with BC Hydro expiring in 2037.

See also "Company History – 2024 – Renewable Power Asset Sell-Down".

Strathmore Solar

Strathmore Solar is a 41 MW solar project, that began commercial operation in March 2022. Strathmore Solar consists of 109,174 photovoltaic panels located on 320 acres of leased industrial land.

Commercial Arrangement – Power Purchase Agreement

All of the energy and renewable energy credits generated by the Strathmore Solar project are sold under a 25-year PPA with TELUS Communications expiring at the end of 2046.

See also "Company History – 2022 – Strathmore Solar begins commercial operations".

<u>Ontario Contracted Facilities</u>

Kingsbridge 1

Kingsbridge 1 is a 39 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, 20 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 is a renewable energy supply contract which 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 April 2035.

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.

Port Dover & Nanticoke

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. On December 20, 2024, Capital Power announced the closing of the previously announced sale of a 49% interest in PDN to Axium Infrastructure Inc. The facility is jointly owned in a 51/49 partnership with Axium Infrastructure Inc. and is operated by Capital Power.

Commercial Arrangement: Electricity Purchase Agreement

PDN has a 20-year feed-in-tariff contract with the Ontario IESO which expires in 2033.

See also "Company History – 2024 – Renewable Power Asset Sell-Down".

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 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

The facility is fully contracted with the Ontario IESO until April 2035.

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 March 31, 2021, cleared the site, seeded it for grass, and then sold the parcel on March 10, 2022 to another company. Capital Power has no further obligations pertaining to the former Roxboro plant site.

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 March 31, 2021, and satisfactorily completed requirements under the Duke ground lease for site remediation but continues to work with both Duke Energy and the North Carolina Department of Environmental Quality to comply with its environmental obligations.

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 Wind

Bloom Wind is a 178 MW wind facility consisting of 54 Vestas V117-3.3 MW turbines. Bloom Wind 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 Wind 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 June 30, 2027. 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 Wind 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 by Capital Power November 30, 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. Under the extension, the tolling agreement will be six summer months of the year from 2026 to 2031 as compared to four summer months through 2025.

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 HRCO 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.

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 / 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.

Midland Cogeneration

Midland Cogeneration is a 1,633 MW natural gas combined-cycle cogeneration facility located in Midland, Michigan that began operations in 1990 and was acquired by Capital Power on September 23, 2022. Capital Power is a 50% owner under a joint venture with John Hancock Life Insurance Company (U.S.A.) and Manulife Infrastructure II Holdings A, L.P.

Commercial Arrangement: PPA & Steam and Electrical offtakes

Midland currently has a PPA in place for 1,240 MW of capacity and energy with Consumers Energy, an investment grade load serving utility (credit ratings of Baa1/A- from Moody's and S&P, respectively) which expires in 2030. Consumers Energy makes capacity payments with pass-through provisions of fuel expenses, maintenance, environmental and demineralized water costs. The uncommitted capacity of the facility is offered into the marketplace where it receives energy, capacity and ancillary service revenues from both MISO and bi-lateral capacity counterparties. In addition, Midland has steam and electricity supply agreements with investment grade agriscience companies located adjacent to the facility which provide stable revenue and a pass through of costs through 2035.

Fuel Supply

Midland has had a long-term asset management and gas supply agreement with a large North American natural gas producer and energy manager since 2008, with the current arrangements expiring in 2025. The agreements provide for 100% of the facility's gas requirements with contract pricing tied to the Consumers City Gate index, which coincides with the fuel cost pass through mechanisms in the facilities PPA and steam and electric supply agreements with behind-the-meter customers. Midland also has contracted for gas transportation and storage services with Consumers Energy until 2030 that provide firm deliveries, load balancing, and optimization opportunities for the facility. In addition to the gas interconnection with Consumers Energy, Midland is also interconnected with Great Lakes Gas Transmission Company providing additional gas supply reliability and flexibility.

See also "Company History – 2022 – Acquisition of Midland Cogeneration Facility".

Frederickson

Frederickson is a 265 MW natural gas combined-cycle cogeneration facility located near Tacoma in Pierce County, Washington that began operations in 2002 and was acquired by Capital Power on December 28, 2023. Capital Power has a 50.15% undivided ownership interest under a joint venture with Puget Sound Energy, whereby the parties are tenants in common. The facility consists of a 1X1 combined-cycle facility comprised of one GE 7FA combustion turbine, one Nooter Eriksen heat recovery steam generator, and a single GE steam turbine.

See also "Company History – 2023 - Acquisition of 50.15% interest in Frederickson 1 Generating Station".

Commercial Arrangement

Fredrickson has two long term unit contingent toll agreements with credit-worthy counterparties. The tolling agreement with Morgan Stanley Group Inc. will terminate in September 2025 and starting October 2025, a tolling agreement with Puget Sound Energy will commence, which will expire in October 2030. Each of the tolling agreements set the terms for energy purchases and entitles the tolling agreement counterparty to the facility's share of the committed capacity.

Fuel Supply

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

Harquahala

Harquahala is a 1,092 MW gas combined cycle facility located 60 miles West of Phoenix in Maricopa County, Arizona. It became commercially operational in 2004 and Capital Power's ownership interest was acquired in a transaction that closed on February 16, 2024. The facility consists of three (3) 501G powered 1 x 1 combined cycle gas turbines. Harquahala is electrically connected to the Hassayampa common bus and connects directly to the Palo Verde pricing hub. Harquahala is a FERC-approved exempt wholesale generator that is authorized to sell power at market-based rates. Capital Power is a 50% owner and operator of Harquahala under a partnership arrangement with an affiliate of a fund managed by BlackRock's Diversified Infrastructure business.

See also and "Company History – 2024 – Completion of Acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility".

Commercial Arrangement

Harquahala revenues are fully contracted through a long-term tolling PPA with an investment grade counterparty through 2031. The PPA provides for the sale of nearly all capacity of Harquahala from January 1, 2024 to December 31, 2031, on a year-round basis and all of the electric energy associated with that capacity sold under the PPA. The PPA is based on a fixed capacity payment for Harquahala, subject to certain availability guarantees, along with a variable energy payment and a start charge. The PPA counterparty is responsible for carbon and other environmental costs pursuant to the PPA.

Energy management services for the Harquahala facility are currently provided by third party service providers. As of January 1, 2025, operation, maintenance, and asset management services are all provided by Capital Power, with those activities having been transitioned from third party service providers over the course of 2024.

Fuel Supply

Natural gas to the Harquahala facility is supplied through the El Paso Natural Gas Company gas interconnection. Fuel procurement, scheduling and delivery are the responsibility of the PPA counterparty.

La Paloma

La Paloma is a 1,062 MW gas combined cycle facility located 30 miles West of Bakersfield in Kern County, California. It became commercially operational in 2003 and Capital Power's 100% equity interest was acquired in a transaction that closed on February 9, 2024. The facility consists of four (4) combined cycle gas turbines. The La Paloma facility is electrically connected to the CAISO and procures fuel at the Kern pricing hub. The La Paloma facility is a FERC-approved exempt wholesale generator that is authorized to sell power at market-based rates.

Commercial Arrangement

The La Paloma facility sells its energy, ancillary services, and capacity into the California power market. La Paloma sells into CAISO through merchant day ahead/real time markets. and ancillary service transactions. La Paloma has secured bi-lateral resource adequacy (RA) contracts for a portion of available capacity with multiple counterparties. The La Paloma facility has currently sold approximately 98% of its capacity through 2026 stepping down to 0% at the end of 2029 pursuant to RA agreements with various investment grade utilities and off-takers. The La Paloma facility can sell energy margin forward either through forward swaps or heat rate call option products which lock in the spark spread margin. The La Paloma facility is required to acquire carbon allowances through California's cap and trade program. It procures carbon allowances monthly at market rates and passes these costs through its energy offers in the CAISO market.

Operations, maintenance, and energy management services for the La Paloma facility are currently provided by third party service providers. Asset management services for La Paloma were transitioned from a third party service provider to Capital Power in 2024.

See also and "Company History – 2024 – Completion of Acquisition of 100% interest in La Paloma Facility and 50% interest in Harquahala Facility".

Fuel Supply

Fuel procurement and delivery are the responsibility of the energy manager. Procurement occurs in the spot markets since there are no fuel supply agreements in place.

<u>Projects Under Construction or in Advanced Stages of Development</u>

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

Halkirk 2

Capital Power has secured the necessary permits and approvals for its updated phase 2 of the Halkirk wind project located in the County of Paintearth, Alberta. The capital cost for the 126 MW phase 2 is expected to be approximately $318 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 more advanced turbine technology, requiring a permit amendment. An amendment application was filed in July 2023, and an amended AUC power plant approval was issued on July 27, 2023. Municipal development permits were then approved in August 2023. Capital Power selected Vestas' V150 4.5 wind turbines for the project and commenced construction in October 2023.

In March, 2024, the Company entered into a 15-year virtual power purchase agreement (VPPA) with Saputo Inc. pertaining to Phase 2 of the Halkirk wind project. The facility is expected to reach COD by March 31, 2025 subject to final regulatory approvals. Once operational, the portion of the wind facility contracted by Saputo will generate approximately 206,300 MWh of renewable electricity per year.

In August 2024, Capital Power announced it's entered into a participation and equity option agreement with Louis Bull Tribe, Samson Cree Nation, Montana First Nation and Ermineskin Cree Nation related to the project.

See also "Company History – 2023 – 15-year renewable energy agreement with Shaw Communications Inc." and "Company History – 2024 – Partnership with Maskwacis First Nations" and "Company History – 2024 – Large-scale virtual power purchase agreement with Saputo Inc."

Maple Leaf Solar

Maple Leaf is a 73 MW solar energy project, located in the Town of Selma, North Carolina. In June 2023, Capital Power announced a 25-year, fixed price renewable power purchase agreement for 100% of the output from the project with Duke Energy Progress. Construction is expected to begin in 2025 with an estimated capital cost of US$165 million and an expected commercial operations date in late 2026, pending completion of the Duke interconnection upgrades. Local zoning approvals were obtained in May 2023 and detailed design and permitting are underway.

See also "Company History – 2023 – Maple Leaf Solar project awarded 25 year contract".

Capital Power was selected for five projects in Ontario with an original capital cost of $650M which is now forecast to come in at $600M. Each of the projects is discussed below:

York Battery Energy Storage System

The York BESS will provide 120 MW of capacity with at least four hours of storage (480 MWh) to the Ontario grid. The facility will be located adjacent to the existing natural gas facility and will connect to the 230KV system via the York substation. Tesla has been selected as the preferred supplier. Construction started August 2024 with COD expected mid-2025.

When completed, this project will be fully contracted with the Ontario IESO until 2047.

Goreway Battery Energy Storage System

The Goreway BESS will provide 50 MW of capacity with at least four hours of storage (200 MWh) to the Ontario grid. The facility will be located on an unused portion of the natural gas facility property and will connect to the 230KV system downstream of the existing Substation utilizing the existing Goreway grid connection. Tesla has been selected as the preferred supplier and contract negotiations are ongoing regarding the construction and O&M contracts.

When completed, this project will be fully contracted with the Ontario IESO until 2045.

Goreway Power Station – Upgrade Project

The Goreway Uprate Project was developed around a turbine efficiency package that will provide a 40 MW increase in the total plant capacity. The uprate consists of improved turbine hot gas path parts and higher output first stage compressor components, together with a peak firing software change.

The uprate was accepted by the IESO in their call for same technology uprates to extend the existing PPA under similar terms until 2035.

York Energy Centre – Upgrade Project

The York Uprate Project was developed around a turbine efficiency package, plus inlet cooling that will provide a 38 MW increase in the total plant capacity. The uprate consists of improved turbine hot gas path parts and combustors together with an air inlet fogging system to improve hot weather performance.

The uprate was accepted by the IESO in their call for same technology uprates to extend the PPA under similar terms until 2035.

East Windsor Generation Facility Expansion

The East Windsor Expansion project is a new 106 MW natural gas generator. It will be located on Capital Power owned land adjacent to the existing East Windsor facility and connect to the 115KV system at the same connection point as the existing facility. General Electric has been selected as the turbine supplier and contract negotiations are ongoing regarding construction and O&M contracts.

Once completed, this facility will be contracted with the Ontario IESO until 2040.

Portfolio Optimization

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 to manage portfolio risk and develop and maintain capability to support Capital Power's growth strategy and to 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, Alabama, Arizona, California, Illinois, Kansas, Michigan, New Mexico, North Carolina, North Dakota, Texas, and Washington. 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 experience 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 total merchant generation capacity in the market.[1]

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 reporting and disclosure practices reflect our commitment to transparency and accuracy. This commitment is demonstrated through integrating our sustainability and financial disclosures in Capital Power's sixth Integrated Annual Report, being published in February 2025. The Integrated Annual Report aligns to the Sustainability Accounting Standards Board standards, as well as the recommendations of the Task Force on Climate-related Financial Disclosures framework (which are now part of the International Financial Reporting Standards Foundation) to disclose information pertaining to climate-related risks and opportunities.

[1] Source: Market Surveillance Administrator, Market Share Offer Control Report, June 2024, MSOC (albertamsa.ca)

We measure and report our performance on an ongoing and comprehensive basis and, in 2024, 20% of executive short-term incentive pay was based on the company meeting certain sustainability targets. The Board receives quarterly sustainability updates and has oversight of our 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 additional capital expenditures or 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.

Health, Safety, Security, and Environment

Health, Safety, Security, and Environment Policy (HSSE Policy)

Our business of constructing, operating, and maintaining power generation and related facilities can present significant risks to human health and safety, and to the environment, if not properly managed. Our Health, Safety, Security, and Environment (HSSE) Management System is designed to minimize the risk of occupational injury and illness, security or emergency-related events, and negative impacts to the environment.

We are committed to the health, safety, security, and welfare of all workers.

This includes:

- the promotion of a zero-injury safety culture which values worker health & safety, and environmental responsibility;
- the proactive identification and management of health, safety, security, and environment-related risks;
- providing employees with the training and resources needed to fulfill their HSSE responsibilities;
- developing a spirit of engagement and co-operation amongst all workers on HSSE matters;
- complying with all applicable laws and regulatory requirements;
- establishing appropriate goals related to HSSE performance and the monitoring thereof;
- reporting all incidents and potential hazards so that we can learn from our shared experiences and prevent future incidents; and
- the continuous review and improvement of the HSSE Policy and the HSSE Management System.

Every Capital Power Employee and Contractor is responsible for our environmental performance, and the health, safety, and security of themselves and their fellow workers and worksites. Capital Power manages its HSSE risks through a company-wide HSSE Management System and measures its HSSE performance against recognized industry and internal performance measures. Compliance audits are conducted by internal and external auditors to verify that the HSSE management program meets the regulatory requirements for the business.

Board approved HSSE objectives are established annually to promote Capital Power's HSSE stewardship and are measured through the HSSE Performance Index (Index). The Index measures performance through five leading performance indicators which recognize and focus attention on proactive activities and continuous improvement.

Health, Safety and Environment Initiatives

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

- Conducts regular HSSE 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 HSSE 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 HSSE regulatory updates to ensure awareness of upcoming regulatory changes.

Specific environmental initiatives and achievements include the following activities:

- Capital Power serves 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.

- Capital Power minimizes the amount of coal ash going to the landfill by selling it for use in cement production. Genesee Units are now off coal and no more coal ash will be produced.

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

- Achievement of an Index of 1.06. This is the 11th consecutive year the Index has finished at or above the target of 1.00.

- Mandatory Investigation 101 training program for leadership. 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 offices, power operating facilities and construction sites have HSSE representatives, or an established health and safety committee as required by regulations.

- 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 began in 2021, with further refinements ongoing.

People

As at December 31, 2024, the total number of persons employed by Capital Power is 741. As of December 31, 2024, approximately 562 full-time, part-time, temporary and casual employees work in Capital Power's Canadian operations and 179 are employed in Capital Power's US operations.

There are four Canadian labour unions, in six bargaining units, and 1 union in the USA which together represent approximately 32% of Capital Power's Canadian labour force and approximately 31% 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 Power Workers Union Local 1000, which represents power engineers and maintenance employees at Goreway.

- the Power Workers Union Local 1000, which represents plant technicians at East Windsor Cogeneration Centre.

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

- the UNIFOR Local 1123, which represents power engineers and maintenance employees at Island Generation.

- the Utility Workers Union of America local 564, which represents hourly operators and maintenance employees at Midland Cogeneration Venture.

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 19, 2021	December 13, 2025

IBEW Local 1007	Edmonton, AB	December 17, 2023	December 13,2025
PWU Local 1000	Brampton, ON	December 5, 2023	December 4, 2026
PWU Local 1000	Windsor, ON	June 6, 2024	June 5, 2027
UNIFOR Local 829	Edmonton, AB	December 18,2022	December 13, 2025
UNIFOR Local 1123	Campbell River, BC	May 1, 2021	April 30, 2025
UWUA Local 564	Michigan, United States	March 1, 2019	March 15, 2025

REGULATORY OVERVIEW

The following is an overview of the principal electricity and 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".

Canada

Federal Government

Greenhouse Gas Regulation – Coal Generation

The *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity 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 tCO_2/MWh on December 31, 2029. In 2024, Alberta phased out the use of coal for electricity with the repowering of Genesee Units 1 and 2, years ahead of the province's 2030 target date.

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 is based on their environmental efficiency as measured in tonnes of carbon dioxide per MWh. Boilers, such as Genesee Unit 3, that meet more stringent efficiency requirements are permitted to operate up to 10 years post EoUL.

For gas turbines, large units (over 150 MW) are subject to a 0.42 tCO_2e /MWh standard, while smaller units (25-150 MW) are subject to a 0.550 tCO_2e /MWh standard (gross basis). The regulation included provisions providing legacy treatment to existing units such that Clover Bar, Joffre, Shepard and Island Generation and therefore they are not impacted by the standards.

Clean Electricity Regulations

On December 17, 2024, the Government of Canada released the final version of the *Clean Electricity Regulations* (CER). The Regulations have been published in Gazette II and are established under the *Canadian Environmental Protection Act, 1999* (CEPA). The CER are part of a broader suite of policies intended to meet the federal government's objective of achieving a net-zero electricity system by 2050.

Starting in 2035, the CER will apply to grid connected units that are greater than 25MW and generate electricity using fossil fuels. The regulations set an annual emission limit (AEL) for each unit based on a prescribed emission intensity and the unit's capacity. The prescribed emission intensity will be 65 tCO_2/GWh for the period between January 1, 2035 and December 31, 2049; and 0 tCO_2/GWh thereafter.

Compliance flexibility by way of using offsets is permitted. The CER will grant an allowance of an additional 35 tCO2/MWh over the prescribed emission intensity to 2050 and 42 tCO2/GWh after. The offsets must be registered within the Canadian system and issued no more than eight years prior to being remitted. The same offset can be applied to the CER and federal carbon pricing or a provincial carbon price that has cross recognition with Canadian offset credits. Additional compliance flexibility will be allowed through banking of AEL credits for use in future years and the transfer of unused AEL credits between units operating in the same jurisdiction so long as the unit is not a coal facility or existing / planned cogeneration facility. Existing units, planned units, or units regulated under the coal-to-gas regulations will not have to comply with the AEL until the end of their prescribed life (EoPL) where the EoPL is defined as 25 years after the unit's commissioning date for existing units, 2049 for planned units, and the end of life assigned to coal-to-gas converted units under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity.* Planned units are defines as a unit that is commissioned between January 1, 2025 and December 31, 2034 where construction begins prior to December 31, 2027.

All of Capital Power's natural gas generation facilities in Canada, including the repowered Genesee 1 and 2 units, qualify as existing units under the CER. As such, each unit will have to achieve compliance with the AEL at the end of their respective EoPL, 25 years after COD.

Natural Resources Canada released the Clean Electricity Strategy on the same day as the CER. The strategy summarizes measures already announced including the CER and Clean Electricity ITCs.

Federal Climate Plan

On December 11, 2020, the Government of Canada released its climate plan (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/tCO2e per year starting in 2023 until achieving a price of $170/tCO2e in 2030.

Pan-Canadian GHG Framework

The Greenhouse Gas Pollution Pricing Act (GGPPA) sets out a federal carbon pricing system based on a two-pronged approach: (i) 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 (ii) an output based pricing system (OBPS) that applies to large industrial facilities, 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/tCO2e in 2019 and increased by $10/tCO2e each year, reaching $50/tCO2e in 2022. On October 11, 2022, the Government of Canada amended Schedule 4 of the GGPPA establishing the carbon price for the 2023-2030 period. The amended schedule increases the carbon price by $15/tCO2e per year starting in 2023 until achieving a price of $170/tCO2e in 2030. In 2024, the carbon price was set at $80/tCO2e.

On September 20, 2020, the Minister of the Environment and Climate Change informed the Government 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. In 2022, the federal government assessed the provincial carbon pricing frameworks, including the TIER framework and the Ontario Emission Performance Standards (EPS) program, against the federal OBPS backstop framework. On November 22, 2022, the Government of Canada announced that Alberta and Ontario will continue to implement their own pollution pricing systems for industrial emissions. TIER and the EPS will remain in place until at least 2026, at which time an interim assessment will be made to confirm provincial frameworks continue to meet benchmark criteria for the 2027-2030 period.

Canada's Enhanced Nationally Determined Contribution

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.

COP28 concluded on December 12, 2023, with an agreement that sets the stage for a transition process. This process is expected to involve significant emissions reductions and increased financing to support climate change mitigation and adaptation globally. The agreement highlights the importance of substantial, ongoing reductions in greenhouse gas emissions, in alignment with 1.5 °C pathways. It also encourages parties to participate in global efforts, taking into account their individual national circumstances. Canada and the US maintained their respective NDCs at 40-45% below 2005 levels by 2030 and 50–52% below 2005 levels by 2030, respectively. The following efforts are the most relevant to the electricity sector:

- Tripling renewable energy capacity globally and doubling the global average annual rate of energy efficiency improvements by 2030.
- Accelerating efforts globally towards net zero emission energy systems, utilizing zero- and low-carbon fuels well before or by around mid-century.
- Transitioning away from fossil fuels in energy systems, in a just, orderly and equitable manner, accelerating action in this critical decade, so as to achieve net zero by 2050 in keeping with the science.
- Accelerating zero- and low-emission technologies, including renewables, nuclear, abatement and removal technologies such as carbon capture and utilization and storage, particularly in hard-to-abate sectors, and low-carbon hydrogen production.

COP29 concluded on November 22, 2024, with an agreement to increase annual funding goals to at least US$300 billion annually, with an overall climate financing target to reach “at least US$1.3 trillion by 2035”. The new goal of at least US$300 billion annually by 2035 is triple the amount of the previous target, aiming to mobilize much-needed finance for developing countries to cut emissions and address the mounting impacts of climate change. No changes were made to Canada’s NDC but indicated an aim to submit the next NDC that are aligned with emission trajectories in-line with mid-century net-zero objectives.

Emissions Reduction Plan (ERP)

On March 29, 2022, the Government of Canada released its inaugural ERP as required under the Canadian *Net Zero Emissions Accountability Act*. The ERP outlined a range of measures the federal government is intending to pursue across all sectors to achieve Canada's 2030 emissions reduction commitments. The ERP included the Government's commitment to pursue a net-zero electricity system by 2035. It also included a commitment by the Government to explore measures to de-risk carbon policy, including potential carbon contracts for differences, to provide greater certainty for investments in decarbonizing technology.

Federal Financial Support for Clean Electricity Projects

The 2023 Federal Budget (Budget) was tabled on March 28, 2023 and included proposals for a number of new and expanded programs and initiatives to support investment across a range of zero and low-emitting technologies to advance the federal government's clean electricity and net-zero objectives. The Budget measures of particular note for Capital Power were the following: (i) reaffirmation of the role and mandate for the Canada Growth Fund (CGF) to support de-risking of large scale decarbonization through instruments such as carbon contracts for differences, (ii) direction by the federal government that the Canada Infrastructure Bank will have a new priority focus on clean electricity, (iii) enhancements to the 50% refundable ITC for carbon capture, utilization and storage, (iv) updates to the 30% refundable Clean Technology ITC that will be available to taxable entities for investments in eligible technologies, (v) a new 15% refundable Clean Electricity ITC that will be available for non-taxable entities for investments in eligible technologies, and (vi) updates to the Clean Hydrogen ITC.

The 2023 Fall Economic Statement (2023 FES), tabled on November 21, 2023, provided additional direction regarding the CGF's mandate in noting that the CGF will allocate $7 billion of its total $15 billion of capital to issue all forms of CCFDs and offtake agreements to support de-risking of investments in decarbonization technologies.

Legislation to implement the CCUS and Clean Technology ITCs were also introduced in November 2023, and progressed in 2024’s Budget and Fall Economic Statement. Bill C-59 (which includes the CCUS ITC and Clean Technology ITC) received Royal Assent on June 20, 2024. Capital Power’s Halkirk 2 Wind, Goreway BESS and York BESS projects are expected to be eligible for the Clean Technology ITC and an accrual of $73 million, based on the respective project-to-date spend, was recorded in 2024.

Federal Cap on Greenhouse Gas Emissions from the Upstream Oil and Gas Sector

On November 4, 2024, the Government of Canada released proposed regulations under the *Canadian Environmental Protection Act, 1999* (CEPA) that, if adopted, will impose a cap on greenhouse gas (GHG) emissions from the upstream oil and gas sector and the LNG sector. The proposed Emissions Cap Regulations, which follow ECCC’s regulatory framework to cap oil and gas sector GHG emissions initially introduced by the federal government in December 2023, propose a cap-and-trade system aimed at reducing emissions from the oil and gas sector to 35% below 2019 levels by 2030-2032. The federal government states that the proposed Emissions Cap will incentivize the oil and gas sector to invest in decarbonization strategies to attain significant emissions reductions and that the cap includes sufficient flexibility to enable continued production growth in the sector.

Although many key details are still under development, the proposal could have implications for the Alberta economy as a resilient supply of natural gas is critical to powering the energy expansion. This may further impact the TIER GHG credit market and the supply and/or demand of eligible offsets or credits. The extent of the impact on TIER remains to be seen and will depend on final design details and the timing or the phase in of the emission cap-and-trade system. Management will engage with the federal and Alberta governments and participate in forthcoming processes, as appropriate.

Mandatory Climate Disclosures for Federal Corporations and Made-in-Canada Sustainable Investment Guidelines

On October 9, 2024, the Government of Canada announced an intention to amend the CBCA to mandate climate-related financial disclosures for large, federally incorporated private companies. The federal government intends to work with provincial partners to harmonize its regulations with similar regulations imposed on public companies by securities regulators. Although Capital Power is a public company and not directly impacted, management is monitoring developments and assessing potential impacts to Capital Power’s subsidiaries.

Until such time mandatory climate-related disclosures under Canada Securities Administrators ruling are finalized, we will continue to prioritize voluntary climate-related disclosures on the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD) framework. To streamline our current voluntary disclosures, we will discontinue voluntary disclosures on guidance from the Global Reporting Initiative, and no longer respond to climate change questionnaires from CDP (the global disclosure system for environmental impacts). Management continues to monitor developments on voluntary climate-related disclosures.

The Government of Canada also announced a plan to deliver Made-in-Canada sustainable investment guidelines. These guidelines will be a voluntary tool for investors, lenders and other stakeholders for identifying (1) “green” activities, to be defined as low or zero-emitting activities that do not have material Scope 1 and 2 emissions, lower or zero downstream scope 3 emissions and sells into or benefits from markets that are expected to grow in the global net-zero transitions; and (2) “transition” economic activities, to be defined as decarbonizing activities that have material scope 1 and 2 emissions, including those with low or zero scope 3 emissions, that do not face immediate demand-side risk and do not create carbon lock-in and path dependency. The federal government has highlighted priority sectors, including electricity, where it will concentrate its efforts on developing eligibility criteria. Management continues to monitor developments and assess impacts should Capital Power pursue sustainable financing in the future.

Public Consultation on Competition Act’s New Greenwashing Provisions

Bill C-59 introduced amendments to Section 74.01 of the Competition Act (Act) to address greenwashing. The Act now targets environmental claims that promote the environmental, social, and ecological benefits of using or supplying a product if the claim is not based on an adequate and proper test. More broadly, it also targets environmental claims that promote the environmental and ecological benefits of a business or business activity that are not based on adequate and proper substantiation in accordance with an internationally recognized methodology. Both of these sections place the burden of proof on the entity making the environmental claim to demonstrate compliance with these provisions.

On July 22, 2024, the Competition Bureau launched a public consultation on the greenwashing provisions seeking feedback from interested parties to inform its future enforcement guidance about environmental claims and implementation of the new provisions. Management submitted comments on September 27, 2024 outlining its concerns around unintended consequences as a result of the new provisions and recommendations on how to mitigate the likelihood of such consequences through guidance. Draft guidelines concerning environmental claims were issued by the Competition Bureau on December 23, 2024 for public consultation. Management submitted additional comments before the February 28, 2025 consultation deadline.

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 ratepayers. Power from merchant generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the Alberta Electric System Operator (AESO), based on offers by generators to sell power. The Market Surveillance Administrator (MSA) is an independent entity responsible for monitoring the behaviour of market participants, including AESO, 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, AESO and AUC rules. The AUC oversees electricity industry matters including approvals of the construction and operation of new power and transmission facilities, regulated rates for transmission, distribution and the 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. Capital Power’s development projects are subject to oversight by the AUC.

The *Responsible Energy Development Act* created a single regulator, the AER, which began operations in June 2013. The AER is responsible for all oil, gas, oilsands and coal mining projects in Alberta. 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.

Alberta Utilities Commission Inquiry into the Ongoing Economic, Orderly and Efficient Development of Electricity Generation in Alberta

On August 3, 2023 the Government of Alberta announced that it had directed the AUC to pause approvals of renewable generation projects until February 29, 2024 and had also directed the AUC to initiate an inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta. The AUC was directed to provide a report to the Minister of Affordability and Utilities by March 29, 2024, with recommendations. The Inquiry was divided into two modules, with the AUC completing its first report on renewable development on January 31, 2024 and its second report on the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability on March 28, 2024.

On February 29, 2024, the Government of Alberta's pause on renewable generation facility approvals was lifted and additional clarity was provided on policies for siting renewable generation. This includes: an "agriculture first" approach to land-use where renewable projects have to demonstrate that they co-exists with agricultural use; a buffer zone for renewable development around specific viewscapes where wind projects will not be permitted and where other projects will be required to undertake a visual impact assessment; creation of standards for reclamation security; and plans for an engagement on use of Crown lands for renewable development. On December 6, 2024, the *Electric Energy Land Use and Visual Assessment Regulation* was introduced to formalize the February policy direction. This includes a map that depicts the pristine viewscapes, visual impact assessment zones and agricultural lands identifies specific locations where projects may not be permitted or face additional scrutiny. Amendments to the *Conservation and Reclamation Regulation* were also announced, requiring reclamation security for wind and solar operations.

Capital Power does not have any active or outstanding applications impacted by the announcement of the AUC inquiry.

Interim Market Power Mitigation Rules

Two interim regulations to address Government of Alberta concerns with market power in the wholesale electricity market were announced on March 11, 2024. Details of the interim regulations are:

- The *Market Power Mitigation Regulation* sets out a secondary price cap in Alberta's market where offers of generators with 5% or higher market share are limited once a hypothetical reference combined cycle unit reaches twice its expected fixed cost (capital recovery and fixed operating) recovery for the month. When the threshold is reached, the offer cap for affected generators will decline to the greater of $125/MWh or 25 times the natural gas price.

- The *Supply Cushion Regulation* enables the AESO to develop procedures to direct or keep on generating assets that cycle offline and cannot re-connect within an hour in the event it anticipates its supply cushion in the market to be less than 932 MW. In the event a generator is directed on, it will be compensated for its startup costs and minimum generation costs in the event the market prices do not cover the costs.

The expedited rules based on the interim regulations were approved by the AUC on June 19, 2024, and came into effect on July 1, 2024. The AUC has initiated a process to consider the AESO's request for final approval of these rules. Management is participating in this process and expects the AUC to complete its determination in Q1 2025.

Alberta Electric System Operator Restructured Energy Market (REM)

On March 11, 2024, the Government of Alberta and the AESO announced plans to restructure the energy market (REM) to address long-term reliability, affordability, and decarbonization objectives. On July 11, 2024, the Minister of Affordability and Utilities announced policy decisions that direct the AESO's technical design of the REM. Specifically, this includes moving forward with a day ahead market, allowing price to be determined by strategic offers of market participants, mitigating the market to limit the potential for excessive exercises of market power, a review of the price cap and floor, and market operational changes (security constrained dispatch and co-optimized dispatch, and shortened settlement intervals). The decision to maintain competitive forces in the market over introducing and relying solely on administrative pricing (which was a feature of the AESO's initial REM proposal) is intended to maintain features of the existing pricing framework.

The AESO initiated a series of consultations on high-level design details on September 10, 2024, and published its high-level design document for written feedback on December 13, 2024. The high-level design includes the introduction of a new day-ahead energy market, a new day-ahead commitment product that is to provide a price signal for assets to commit to be available in real-time, and two new ramping products in the real-time market. The REM proposal introduces changes to the pricing framework, notably increasing the price cap from $1,000/MWh to $3,000/MWh, lowering the offer cap from $999.99/MWh to $800/MWh, introducing administrative scarcity pricing and lowering the price floor to -$100/MWh. The Government has also directed the AESO to design a congestion management mechanism that is market based and respects incumbency as part of the REM design.

On December 10, 2024, the Minister of Affordability and Utilities issued a direction letter to the AESO. In it, the AESO was directed to continue developing the detailed design of the REM in consultation with stakeholders, with a view to finalizing the REM design before the end of 2025. The Government intends to then bring forward any necessary policy tools to allow the REM rules to be enacted through legislation, not the AUC approvals process. The Government's intent is for the rules to be enacted by the end of 2025 but not brought into effect until the REM is implemented, which is anticipated in 2027.

Management is participating in the AESO's consultation to progress the market design.

Transmission Policy Review

On October 23, 2023, the Government of Alberta released a discussion paper identifying different features of the existing transmission policy framework that are being reviewed to ensure the affordability, reliability and decarbonization of Alberta's electricity system. Among other things, the discussion paper discusses potential changes to the current policy framework for allocating wires and ancillary services costs between different transmission users, the transmission planning framework, and provisions for intertie restoration and expansion. The Government of Alberta invited comments to inform potential next steps and what changes, if any, may be warranted and Capital Power has actively participated in the process.

On July 11, 2024, the Alberta Minister of Affordability and Utilities announced policy direction on long-standing transmission policy. On a go forward basis the policy direction is to move away from the current zero-congestion transmission planning standard to an optimally planned transmission planning standard where costs of transmission is evaluated against the benefits. For new transmission infrastructure, costs will be allocated based on cost causation principles, similarly all ancillary services costs will be allocated to those that cause the cost. This is a shift away from the load-pays policy as generators will now also incur cost should they cause them. These changes will be integrated in the AESO's market reform engagement.

On December 10, 2024 the Government of Alberta issued a direction letter to the AESO outlining further decisions on transmission policy to provide guidance to the AESO with respect to location signals, intertie expansion and line losses. To improve location signals when siting new generation, the existing Generator Unit Owner's Contribution will be replaced with a non-refundable Transmission Reinforcement Payment (TRP) whose proceeds will be used to offset transmission costs. There will be no upper limit on the TRP and will be implemented through changes to the AESO's tariff. To restore the intertie, the AESO has been directed to develop plans and file them with the AUC by December 31, 2026 to restore the Alberta-BC path to approximately 950 MW, procure and maintain high levels of ancillary services to allow full import flows, and replace the Alberta-Saskatchewan intertie which is nearing the end of its useful life – in doing so there is an expectation that the AESO will increase its path rating. Finally, the AESO is directed to replace its line loss methodology with a system-wide average starting January 1, 2027.

Government of Alberta Resolution under Alberta "Sovereignty Act"

On November 27, 2023, the Government of Alberta introduced a resolution under *the Sovereign Alberta Within a United Canada Act ("the Sovereignty Act")*. The resolution outlines a series of measures that Alberta would propose to pursue to ensure the Federal CER, as proposed or in any form that intrudes on provincial jurisdiction over electricity generation and that Alberta views as presenting a risk to reliability and affordability of electricity for Albertans, are not implemented in Alberta.

As tabled, the resolution would:

- Enable Cabinet to order all provincial entities not to recognize the constitutional validity of, enforce, or cooperate in the implementation of the CER in any manner, to the extent legally permissible. This order would not apply to private companies or individuals.
- Ask the Government to work with the AESO, AUC and others to implement various reforms to Alberta's electrical system to ensure grid affordability and reliability.
- Instruct the government to work with industry, regulators and other groups to study the feasibility of establishing a provincial Crown corporation for the purpose of bringing and maintaining more reliable and affordable electricity onto the grid in the event that private generators find it too risky to do so under the CER.
- Urge the government to use all legal means necessary to oppose the implementation and enforcement of the Federal CER in Alberta.

The Government's announcement regarding the resolution noted that any future Crown corporation, in the event one was established, would work with industry and other stakeholders to bring on needed electricity onto the grid, either through building new generation or purchasing existing generation assets that private industry would otherwise not build or shut down due to the uncertainty and penalties established by the CER. The Crown corporation could also be used as a means of assisting and partnering with industry to de-risk investments in nuclear power and other emerging generation technologies if needed.

Management understands that the measures outlined in the resolution are intended as a "last resort" and would only be pursued at a point in the future after Alberta has explored all other measures to address its concerns with the CER, and then only after consultations involving industry and other stakeholders. On this basis, Management does not currently believe there will be any immediate impact for Capital Power's Alberta operations or the Alberta electricity market. Management will continue to engage with the Government of Alberta on market design and the CER and actively participate in any further consideration of any of the measures identified in the Sovereignty Act resolution to mitigate any potential impacts.

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 2024. 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.

Under the Off-Coal Agreement, Capital Power is required to cease coal-fired emissions from Genesee 1, Genesee 2 and Genesee 3 by the end of 2029. On June 18, 2024, Capital Power announced that the Genesee Generating Station is 100% natural gas-fueled, resulting in the facility being off coal over five years ahead of the Alberta government mandate. As part of the Genesee Repowering project, the facility completed simple cycle commissioning for Unit 1 and Unit 2 on May 3, 2024, and June 28, 2024, respectively, and Unit 3 has transitioned to natural gas. The project completed combined cycle commissioning in Q4 2024 with Unit 1 achieving COD on November 18, 2024 and Unit 2 on December 13, 2024.

Technology Innovation and Emissions Reduction (TIER) Regulation

On January 1, 2020, the Government of Alberta replaced the *Carbon Competitiveness Incentive Regulation* with the TIER for large industrial emitters. Under TIER, facilities can physically reduce their emissions to the target or:

- use emission performance credits (EPCs) 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 the prevailing carbon price under TIER which in 2024 was $80 per tonne.

For electricity, TIER is based on a high-performance benchmark emission intensity. In 2024 this is 0.3352 tCO2e/MWh.

TIER imposes limits on the use of EPCs and offsets within each compliance year, which are 70% for 2024, increasing to 90% in 2026. TIER also imposes expiry periods on TIER eligible carbon credits. New offsets with 2023 vintages and later expire after five years while offset and EPCs with 2017-2022 vintages will continue to expire after eight years.

On June 17, 2022, the Alberta Environment and Protected Areas (AEPA) launched the formal review of the TIER Regulation with Alberta's intention to meet the minimum federal GHG benchmark criteria in order to preserve provincial jurisdiction of the carbon pricing framework for large emitters. The key changes proposed relate to committing Alberta to adopt the federal carbon price schedule through 2030, introducing a 2% per year reduction to facility-specific and high-performance benchmarks until 2030, aligning the Electricity Grid Displacement Factor used as the basis for offsets with the electricity TIER benchmark by 2030, and increasing the credit usage cap from 60% to 90% by 2026. On November 22, 2022, the Government of Canada announced that Alberta's TIER framework for industrial emissions will remain in effect from 2023 to 2030. On December 15, 2022, the AEPA released the *TIER Amendment Regulation*. As part of the TIER amendments, the electricity benchmark declines by 2% per year starting on January 1, 2023 reaching 0.3108 tCO_2e/MWh in 2030.

The TIER amendment Regulation also includes sequestration credits and capture recognition tonnes (CCUS credits) as new compliance instruments. Capture recognition credits enable large emitters and opt-in facilities to reduce sequestered emissions from total regulated emissions at carbon capture sites. Under the CCUS credits, facilities capturing CO_2 on site can claim the CCS reductions once captured. Sequestration credits enable recognition under the federal Clean Fuel Regulations.

Capital Power's 2024 TIER compliance obligation must be paid in the second quarter of 2025. The Company intends to retire offsets and EPCs for approximately 70% of the 2024 compliance obligation and purchase fund credits at the $80/tCO2e 2024 cost for the remaining 30% of our obligation. The rest of our offsets and EPCs in inventory will be saved for compliance or market sales 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 2024 reporting period, split by Capital Power's generating assets for the 2024 reporting period (under TIER), is comprised as follows:

- Genesee 1 and 2 are expected to pay approximately $41.2 million.

- Genesee 3 is expected to be approximately $29.5 million.

- Genesee Repower 1 and 2 are expected to pay approximately $14.5 million.

- Genesee Mine has opted into the TIER program and the cost for 2024 is expected to be approximately $0.7 million.

- Clover Bar is expected to be approximately $4.7 million.

- Shepard Energy Center is expected to be approximately $1.5 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 $41 million in Alberta Compliance offsets in 2024.

Alberta's Emissions Reduction and Energy Development Plan

On April 19, 2023, the Government of Alberta released Alberta's Emissions Reduction and Energy Development Plan (ERED). The ERED included an aspiration of achieving a carbon neutral economy – net zero – by 2050 in Alberta but did not specify any other targets. It noted Alberta's plan for emissions reduction will rely heavily on technology such as carbon capture and storage, hydrogen, and small modular reactors and be balanced with a commitment to maintaining affordability, reliability and energy security. The Government of Alberta sees a continued role for natural gas-fired generation in the province for decades to come.

The ERED's recognition of the important continued role for natural gas in Alberta's power system, and the role for CCUS, among other technologies, are consistent with the Company's expectations for decarbonization of Alberta's electricity system. The Company will continue to engage with the Government of Alberta on matters relating to decarbonization and Alberta's electricity system.

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, AEPA released the draft Ambient Air Quality Objectives (AAQOs) for nitrogen 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. AEPA has not released the final AAQOs.

Alberta Environment Water Availability Engagement

In October 2024, AEPA started a public consultation process to identify opportunities or barriers that can be addressed to enhance the water management system in Alberta. The engagement is intended to inform new or updated policy and regulatory tools to optimize the water management system to accommodate population changes, economic growth, and water variability.

This initiative is relevant to Capital Power's existing North Saskatchewan River water diversion licenses for Genesee and the Clover Bar facilities. Consultation is ongoing, and Capital Power remains engaged to identity potential opportunities and challenges for any proposed amendments that may result from the engagement process.

Alberta Carbon Capture Incentive Program

On November 28, 2023, the Government of Alberta announced the Alberta Carbon Capture Incentive Program (ACCIP) which will support and accelerate the development of new CCUS infrastructure in Alberta by providing hard-to-abate industries with a grant of up to 12 per cent for new eligible CCUS capital costs. ACCIP will be available to power generation projects and is expected to build on the previously announced Federal CCUS ITC. The grant will be paid in three installments over three years starting after one year of operation. Applicants must meet reporting requirements by providing project reports between the grant instalment payments. A portion of ACCIP funding will come from Alberta's existing TIER fund.

Capital costs eligible for the grant include the costs to convert existing equipment to monitor and track CO2 for CCUS; and the purchase and installation of approved equipment for an eligible CCUS project, provided an eligible storage or use of the CO2 exists (any utilization which permanently sequesters CO2 will be eligible).

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.

In June 2021, BC Hydro published a draft IRP. The draft indicated 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 expired in April 2022. BC Hydro affirmed this intention in the final IRP that was filed with the BCUC in December 2021. The 2021 IRP proceeding was finally decided upon on March 6, 2024. While BC Hydro did indicate that it would consider Island Generation and other natural gas-fired facilities in future IRPs if fueled with renewable natural gas, the BCUC noted that at present Island Generation is reliant on fossil fuels and therefore in conflict with BC Hydro’s IRP objective of reducing greenhouse gases through electricity.

Separate from its IRP development process, in September 2021, 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. On May 16, 2022, Capital Power and BC Hydro executed a 4.5 year EPA through October 2026 for Island Generation, with the term reflecting the expected time required by BC Hydro to undertake repairs to the submarine cables. BC Hydro subsequently filed the EPA with the BCUC for approval on July 8, 2022 with the BCUC granting approval in a decision issued on November 10, 2022. See also "Company History – 2022 – 4.5-year contract renewal for Island Generation".

As part of the 2021 IRP, in March 2023, BC Hydro advised the BCUC that it was working on a "Signpost" update to their 2021 IRP in response to the Government of BC's announcements issuing an Environmental Assessment certificate for Cedar LNG, the establishment of a new energy action framework, and increasing load forecast. The Signpost update, filed with the BCUC on June 15, indicated an increase in BC Hydro's demand forecast and also a reduction in supply expectations resulting in the need for BC Hydro to accelerate its plans to address both capacity and energy shortfalls. As a result of this, BC Hydro initiated a call for power on April 3, 2024, with initial intention of procuring 3,700 GWh of clean energy from greenfield projects that are able to achieve operations as early as fall 2028. On December 9, 2024 BC Hydro announced that they had successfully procured 5,000 GWh of wind generation. Capital Power did not participate in this procurement.

In June 2024, BC Hydro initiated consultation on its planned 2025 Integrated Resource Plan (IRP) with further consultation expected to occur into 2025. Management will continue to monitor and participate in this process as necessary.

British Columbia Output-Based Carbon Pricing System

The Government of BC announced plans, effective April 1, 2018, to escalate its $30/tCO2e carbon tax by $5/tCO2e per year until it matched the federal carbon tax floor of $50/tCO2e in 2022. On April 1, 2022, BC's carbon tax rate rose from $45 to $50/ t$CO_2$e. Since then the carbon tax has increased in alignment with the federal carbon tax, increasing $15/tCO2e each April 1. Capital Power's operations in BC do not have any carbon tax exposure.

As part of its 2023 budget, the Government of BC announced the transition to a provincial OBPS beginning in April 2024. The OBPS will ensure emissions reductions for industry continue while also providing flexible options, such as carbon offsets, to meet compliance obligations. BC's current industrial pricing system will remain in place for a transition year with OBPS implementation starting in April 2024.

Net-Zero New Industry Intentions

On July 5, 2023, the BC Climate Action Secretariat (CAS) released the Net-Zero New Industry Intentions Paper (Paper). BC is proposing to amend the Greenhouse Gas Industrial Reporting and Control Act and its regulations to implement the Net-Zero New Industry Policy (Policy). The Paper did not discuss the benchmarks for any industrial sector. Under the Policy, new facilities will be required to develop net-zero plans to achieve net-zero emissions in 2050 (2030 for LNG projects) and every year thereafter. The net-zero plan would have to be approved by the CAS before a facility is permitted to proceed.

The contract for Capital Power's Island Generation has provisions that trigger amendments as a result of changes in GHG costs, the effect of which will limit the impact of any changes to carbon compliance costs.

<u>Ontario</u>

Ontario's electricity market is often referred to as a "hybrid market" as it has a competitive wholesale market but leverages contracts to meet long-term reliability. The competitive wholesale market for energy and operating reserve opened in May 2002. The IESO held their first capacity auction to support short term supply balancing in 2020. Most generating facilities remains under contract with the IESO or are rate regulated. Hydro One operates approximately 98% of Ontario's transmission network.

The Ministry of Energy provides the overall regulatory framework and planning for energy in Ontario, while the Ontario Energy Board provides overall regulatory oversight of the electricity sector. The IESO is responsible for the administration of the wholesale electricity markets, operation and reliability of the grid, resource adequacy planning, administration of contracts for electricity resources, and promotion of electricity conservation.

Market Renewal Program (MRP)

Ontario's MRP is a set of coordinated market and IESO system reforms intended to improve market transparency, competitiveness, and real-time unit scheduling. It will introduce Locational Marginal Pricing, market power mitigation, and a financially binding day-ahead market. MRP design work is complete and the IESO Board unanimously approved the market rule amendments associated with MRP on October 18, 2024. The IESO is targeting May 1, 2025 to transition to the new market.

Management has been actively involved in MRP stakeholder engagement sessions, working groups, and user tests in preparation for the transition to the new market. MRP will trigger amendments to the Company's generating contracts with the IESO. While the overall impact MRP will have on the Company will largely depend on these amendments, the Company, if necessary, may leverage various provisions within the contracts that are intended to protect suppliers from adverse effects resulting from market rule changes. Management continues to work with the IESO to minimize the impact MRP will have on its existing fleet.

On November 7, 2024, a consortium of market participants that owns non-quick start natural gas generating units, including the Company, submitted an application to the Ontario Energy Board (OEB) appealing the MRP market rule amendments. The application requests the OEB to review the amendments for consistency to the *Electricity Act 1998* and to determine if MRP unjustly discriminates against a class of market participants. The hearing is now underway, and the OEB is set to make a ruling by March 6, 2025.

Ontario's Affordable Energy Future: The Pressing Case for More Power

On October 22, 2024, the Ministry of Energy and Electrification released the government's vision for energy in a report titled *"Ontario's Affordable Energy Future: The Pressing Case for More Power."* The report highlights the important role electricity plays in Ontario's economy and the government's plans to address rapidly growing energy demand while keeping costs affordable. The report also articulates the important role electrification will have in reducing provincewide emissions and how critical natural gas generation is in supporting the energy transition and grid reliability.

The government's Powering Ontario Growth Plan remains at the forefront of the government's efforts to maintain a reliable, affordable, and clean energy system. The Powering Ontario Growth Plan was released in July 2023. The plan includes several critical initiatives like predevelopment work to site new large-scale nuclear generation at the Bruce generating facility, development of three small modular reactors at the Darlington site, advancement of large hydroelectric storage projects, optimization of hydroelectric generating assets, rollout of energy efficiency programs, and new transmission development. The plan also includes the IESO's procurements for new energy generation.

Bill 214: Affordable Energy Act

The Minister of Energy and Electrification introduced *Bill 214: the Affordable Energy Act, 2024* on October 23, 2024, and the Bill received Royal Assent on December 4, 2024. The overall purpose of the Bill is to enact certain parts of the government's energy vision into legislation. For example, the Bill expands the purpose of the *Energy Act, 1998* and the IESO to include the promotion of electrification and the facilitation of energy efficiency by using electricity to reduce Ontario's overall emissions. The Bill also creates a legislative requirement for the Ministry to carry out integrated energy plans every five years. Lastly, the Bill includes amendments to the *Ontario Energy Board Act, 1998* that will allow the Lieutenant Governor in Council to amend the distribution system code or the transmission system code on matters related to cost allocation or recovery.

Electrification and Energy Transition Panel

In 2022, the Ministry of Energy (now the Ministry of Energy and Electrification) established the Electrification and Energy Transition Panel to be a short-term advisory body to help the government prepare for the energy transition. The government released the Panel's final report in January 2024, in which they provided 29 recommendations related to governmental commitments, regulatory policies, Indigenous community relations, and stakeholder engagement. The Panel flagged the need for further policy direction for the role of natural gas within the energy transition, integrated long-term energy planning between electricity and natural gas, and a review of Ontario Energy Board activities to ensure they remain consistent with the goals of a clean energy economy. The Panel's recommendations have been foundational to many of the actions the Ministry has taken after its release including matters related to natural gas pipeline expansion, integrated planning, and the creation of an energy vision.

IESO Resource Adequacy Framework and Procurements

On December 11, 2023, the IESO announced that it would be launching a series of long-term competitive procurements to secure up to 5000 MW of non-emitting energy from new wind, solar, biofuel and hydro facilities. The Long-Term 2 RFP (LT2) would be the first of the procurements, launching in 2025 with an initial target of 2000 MW of new generating capacity to be added by 2030. Subsequent procurements would be held every other year to balance their supply against rising demand. On August 28, 2024, the Honourable Stephen Lecce, the Minister of Energy and Electrification, announced that the government directed the IESO to target 5000 MW of new generating capacity to be procured by 2034, making it the largest competitive energy procurement in the province's history. In addition, the Minister directed the IESO to look for ways to accelerate the procurement timelines and announced that LT2 will be technology agnostic. The Minister also confirmed that LT2 participants will need to have municipal support for their projects, projects are not to be developed in speciality crop areas, and ground-mounted solar cannot be developed on prime agricultural lands. The Minister also announced that the projects located in Northern Ontario and projects with Indigenous community participation are to be prioritized.

The IESO released an updated electricity demand forecast on October 16, 2024. The forecast showed even higher annual demand growth resulting from step changes in EV manufacturing, industrial growth, and data centre interconnection requests. This new forecast projects electricity demand to increase 75% by 2050. For comparison, the IESO was projecting a 60% increase in electricity demand by 2050 in their Annual Planning Outlook (APO) that was released earlier in the year. In response to the revised outlook, the Minister yet again increased the procurement target. On December 11, 2024, the Minister directed the IESO to now procure up to 7500MW of new generating capacity by 2034. The Minister also requested the IESO to report back to the government on procurement options for long-lead energy resources like hydro generating facilities and long duration energy storage, and to provide contracting options for existing and new small scale electricity generation.

LT2 is set to launch in 2025 with separate procurement streams for capacity and energy. Subsequent procurements are expected to be held annually.

The IESO also launched their second medium-term procurement (MT2). MT2 will award flexible, 5-year contracts to successful proponents who have generating facilities coming off an IESO contract on or before April 30, 2029 (such as Capital Power's Kingsbridge 1 facility). In mid-January 2025, Capital Power submitted a bid for its Kingsbridge 1 facility, and the IESO's announcement of the successful proponents is expected later in 2025.

Management believes Ontario's overall electricity needs and the IESO's commitment to awarding contracts through competitive procurements will continue to provide opportunities for the Company, including possible re-contracting opportunities for existing assets. Management remains involved in the IESO's engagements related to resource adequacy, the APO, and procurements.

Emissions Performance Standards (EPS)

The Ontario Minister of the Environment, Conservation and Parks (MECP) amended the EPS to meet stricter benchmark criteria set by the Federal Government and to extend the program to 2030, effective January 1, 2023.

Under the EPS, the carbon price will align with the minimum Federal carbon price of $80/tCO2e for the 2024 compliance period, increasing by $15/tCO2e per year to $170/tCO2e in 2030. The performance standard for generating electricity using fossil fuels declined from 0.370 tCO2e/MWh to 0.310 tCO2e/MWh effective 2023 and will remain at that level until 2030.

The contracts for the Company’s York Energy, East Windsor and Goreway facilities have provisions that trigger amendments as a result of changes in GHG cost, the effect of which will limit the impact of changes to carbon compliance costs.

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

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 Federal Power Act 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 Regional Transmission Organizations. RTOs are voluntary organizations operated by Independent System Operators independent of market participants. ss 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.

Greenhouse Gas Regulation

In 2023, the United States Environmental Protection Agency (EPA) announced a proposed rule that aims to curb greenhouse gas emissions for coal, gas, and oil-fired power plants that run at least 50% of the time. The final rule, issued in May 2024, requires existing coal and new natural gas fired power plants to mitigate their carbon emissions based on a tiered system of compliance ranging from utilizing low emissions fuels for newly constructed gas turbines that run infrequently, to 90% carbon capture for newly constructed gas turbines that run frequently. The rule has faced several legal challenges in court and is expected to be overturned in 2025 by the new U.S. presidential administration. If the rule is overturned, Capital Power will no longer have a regulatory requirement at the federal level to accelerate mitigation of greenhouse gas emissions. However, decarbonization requirements at the state level will still apply.

Inflation Reduction Act (IRA)

The IRA passed by Congress and signed into law in August of 2022 puts the United States on a projected path to reduce greenhouse gas emissions 40% below 2005 levels in the next decade. Of the IRA's $369 billion investment in addressing climate change, $270 billion will be delivered through tax incentives, putting Treasury and the Internal Revenue Service (IRS) at the forefront of IRA implementation.

In 2024, the Treasury Department prioritized finalizing rules for provisions that allow the transfer and direct payment of clean energy tax credits according to comments made by the assistant Treasury secretary for tax policy. Those provisions of the law are meant to extend credits to tax-exempt entities that have previously not been able to participate in the traditional tax equity market, including nonprofits and state and local governments. More than 200 entities registered to use elective pay or transferability and submitted pre-filing registrations for more than 1,600 projects in anticipation of the guidance.

In addition, Treasury issued initial guidance on the technology-neutral clean electricity production and investment credits that begin in 2025. Enacted in the Inflation Reduction Act, the tech-neutral breaks will be available for clean energy projects that start construction in 2025. This guidance is a step towards replacing the Section 45 production tax credit (PTC) and Section 48 ITC — two breaks widely viewed as instrumental in the ongoing expansion of American solar and wind. Only certain technologies are currently eligible for the two credits: Section 45 allows wind, biomass, geothermal, solar, irrigation power, municipal solid waste, hydropower and marine energy, while Section 48 allows fuel cells, wind, waste energy, storage, biogas, microgrids and other energy properties. The new rules will offer tax credit eligibility awarded to zero-emissions energy sources, regardless of the technology. That includes fossil fuel generation, so long as it is certified as zero-emission.

The current Republican executive and legislative branches of the federal government are expected to roll back provisions in the IRA in some form. It is anticipated that the tech-neutral PTC and ITC tax credits are at moderate likelihood of being rolled back in 2025, though changes to the framework that offer safe harbor for projects that have already reached certain milestones is being considered. Any renewable project that is under construction — namely Hornet, Maple Leaf, and Bear Branch — may lose the tax credit benefits from the IRA. Management continues to monitor the state of the tax credits as federal budget conversations continue.

California Greenhouse Gas Regulation

California implemented GHG regulations under several authorities including the Global Warming Solutions Act of 2006. The initial target was to achieve 1990 statewide emission levels by 2020, representing approximately a 15% reduction in GHG emissions in California compared to a "business as usual" scenario. In September 2016, the target was revised to an emissions reduction goal of 40% below 1990 levels by 2030. In 2018, the target was again revised (Clean Energy Standard) to a goal of 100% of electric load to be served by zero carbon resources by 2045. The Clean Energy Standard is specific to the electricity sector.

The Clean Energy Standard was signed in September 2018 and implements a goal of 100% of electric load to be served by zero-carbon resources, which includes hydro and nuclear resources as well as renewables, by 2045. In September 2022, legislators adopted two additional clean energy targets: (i) AB 1279 requires the state (not just the electricity sector) to reach net zero greenhouse gas emissions by 2045 at the latest and requires anthropogenic GHG emissions to be reduced to at least 85% below 1990 levels by 2045, and (ii) SB 1020 sets interim clean energy targets for sales to retail customers of 90% by 2035, 95% by 2040, and 100% by 2045. It also accelerates 100% of state agencies electricity sales be clean energy from 2045 to 2035. SB 1020 includes requirements for the CPUC to provide confidential PPA data to assist with transmission planning and the CPUC to provide an annual report on reliability in the context of the clean energy targets.

In the fourth quarter of 2023, the California legislature passed two bills that will require certain companies doing business in California to disclose their climate-related financial risks and their scope 1, 2, and 3 GHG emissions. These new laws were the first of their kind in the United States and have compliance deadlines of 2026, and 2027, respectively. The legislation requires the California Air Resources Board (CARB) to issue a formal rulemaking process prior to implementation of the laws, which is expected to occur later this year. Following the acquisition of the La Paloma Generating Plant in McKittrick, CA, Capital Power will be required to disclose climate related information in the state in accordance with these requirements. In September 2024, the state legislature passed SB 219 which grants CARB an extended deadline of six months to complete their rulemaking process for SB 253, moving the CARB rulemaking deadline from January 2025 to July 2025. An extended CARB rulemaking deadline, coupled with outstanding legal challenges that have been raised against SB 253, increase the likelihood that relevant compliance deadlines for Capital Power to report scope 1, 2, and 3 GHG emissions will be pushed out beyond current legislatively mandated deadlines. In December 2024, CARB issued a memo indicating that companies who make good faith efforts to meet the reporting requirements in 2026 will not be punished for incomplete disclosures, but the disclosure obligations will still remain in effect. The California legislature also passed a law that will require companies that purchase or sell voluntary carbon offsets (VCOs) to disclose specific information on the transactions. The original bill text was relatively vague and clarifying legislative activities are currently ongoing. Capital Power is required to disclose any purchase and sale of VCOs in the state starting in January 2025.

Washington State Carbon Market Legislation

In March 2024, the Washington legislature voted in favor of linking the statewide carbon trading market with California and Quebec. Further, in November 2024, voters in Washington considered a ballot initiative (Initiative 2117) that would have repealed the cap-and-invest program designed to reduce GHG emissions by 95% by 2050, if successful. The election results ultimately protected the cap-and-invest program, leaving California and Quebec to begin their own regulatory processes to determine whether to link with the Washington state market.

On January 1, 2025, SB 6058 goes into effect in Washington, making it easier to link the state market with the California and Quebec markets. Immediately, the allowance purchase limit for a covered entity or an opt-in entity will increase from 10% to 25% of the allowances offered during a single auction. There will also be a subsequent rulemaking that is expected to begin in 2025 that will determine compliance periods and potentially revise the definition of an electricity importer. Once Washington formally links with another carbon market, the legislation also has provisions that changes holding limits for general market participants. Until Washington links with another jurisdiction, general market participants (GMPs) cannot own more than 10% of the total allowances to be issued in a calendar year ("vintage-year"). After linkage, there will no longer be a vintage-year holding limit for GMPs. The Washington State Department of Ecology will also have the ability to reduce monetary penalties, or the number of penalty allowances required to be submitted for violations throughout the first compliance period or until Ecology enters into a linkage agreement, whichever is sooner. The Frederickson 1 Generating Station will likely not be financially impacted by Initiative 2117, as its carbon costs will be covered by Morgan Stanley or PSE through September 2030.

Michigan Legislation

On November 28, 2023, the Michigan Governor signed a legislative package that includes a goal of 100% clean energy in the state by 2040, and sets new renewable energy targets for the Michigan state. The legislation requires Midland Cogeneration to achieve GHG emission reductions that are the functional equivalent of deploying on site Carbon Capture and Storage with a 90% capture rate at the facility. Management is working towards a plan to achieve that clean energy goal and it must be submitted under the legislation to the Michigan Public Service Commission by 2030.

North Carolina

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 currently owns one facility in North Carolina: Beaufort, which is in the non-RTO part of North Carolina.

Beaufort is a 15 MW solar project contracted with Duke Energy Progress, LLC through 2030.

New Mexico

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

Alabama

Capital Power owns Decatur, 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.

Kansas

Capital Power owns Bloom Wind, 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 Wind is a FERC approved exempt wholesale generator that is authorized to sell energy, capacity and ancillary services at market-based rates.

Bloom Wind 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 Wind".

Arizona

Capital Power owns Arlington Valley, a 600 MW gas-fired combined-cycle generation facility located in Arlington, Arizona, and 50% of Harquahala, a 1092 MW gas-fired combined-cycle generation facility, located in Harquahala, Arizona. Arizona is not part of a regional transmission organization or independent system operator, and falls into the DSW market within the Western Electricity Coordinating Council. Planning and grid operations are managed by vertically integrated utilities, and in most areas of the state, transactions are bilateral and must be scheduled through the incumbent utility. Three major utilities, Arizona Public Service, Tucson Electric Power and Salt River Project serve the majority of Arizona's electricity demand. These utilities also participate in the WEIM, a real-time energy market established to manage variations in demand and generation across a wider footprint including DSW, CAISO and the Pacific Northwest. The WEIM is operated by CAISO. Arlington Valley and Harquahala are FERC approved exempt wholesale generators that are authorized to sell power at market-based rates.

Illinois

Capital Power owns Cardinal Point Wind, a 150 MW 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.

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.

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.

Michigan

Capital Power jointly owns Midland Cogen otherwise known as MCV, a 1633 MW gas fired combined electrical and steam generation facility located in Midland, Michigan. Midland Cogen is a major wholesale supplier of electrical energy to customers in Michigan and the midcontinent, and a supplier of bulk process steam energy to proximate agriscience production companies operating in the MISO region.

Washington

Frederickson is a 265 MW natural gas combined-cycle cogeneration facility near Tacoma in Pierce County. Contracts are bilateral and must be scheduled through the current utility. Frederickson is a FERC approved exempt wholesale generator that is authorized to sell power at market-based rates.

California

La Paloma is a 1,062 MW natural gas fired generation facility in Kern County, California. The state operates a competitive wholesale power market, managed by CAISO. The CAISO market represents approximately 80% of electricity demand in California. CAISO schedules the operation of the transmission lines of the state's three large investor-owned utilities (IOUs), which retain ownership of the transmission lines. Independent power producers compete to sell their power to the IOUs and other entities such as municipal utilities, community choice aggregation programs, energy service providers and irrigation districts.

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 2024 Integrated Annual Report for the year ended December 31, 2024 which section is incorporated herein by reference and is available on SEDAR+.

COMMON AND PREFERRED DIVIDENDS

Common Dividends

For the three most recently completed financial years, the Company has declared the following: (i) on July 30, 2024, the Company announced a 6% dividend increase for its Common Shares effective for the third quarter 2024 dividend for an annualized dividend of $2.6076 per Common Share, (ii) on August 2, 2023, the Company announced a 6% dividend increase for its Common Shares effective for the third quarter 2023 dividend for an annualized dividend of $2.46 per Common Share and (iii) on August 2, 2022, the Company announced a 6% dividend increase for its Common Shares effective for the third quarter 2022 dividend for an annualized dividend of $2.32 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.

On 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. On August 1, 2023, the Company reinstated the DRIP. Eligible shareholders were entitled to participate in the DRIP commencing with the Company's third quarter 2023 cash dividend. 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**
23 Feb 22	$0.5475
29 Apr 22	$0.5475
2 Aug 22	$0.58
28 Oct 22	$0.58
28 Feb 23	$0.58
28 Apr 23	$0.58
2 Aug 23	$0.615
31 Oct 23	$0.615
27 Feb 24	$0.615
30 Apr 24	$0.615
30 Jul 24	$0.6519
29 Oct 24	$0.6519
25 Feb 25	$0.6519

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**
23 Feb 22	$0.1638125
29 Apr 22	$0.1638125
2 Aug 22	$0.1638125
28 Oct 22	$0.1638125
28 Feb 23	$0.1638125
28 Apr 23	$0.1638125
2 Aug 23	$0.1638125
31 Oct 23	$0.1638125
27 Feb 24	$0.1638125
30 Apr 24	$0.1638125
30 Jul 24	$0.1638125
29 Oct 24	$0.1638125
25 Feb 25	$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.

On December 31, 2023, the annual fixed dividend rate on the Series 3 Shares was reset pursuant to their terms to 6.860% for the next five-year period ending December 31, 2028. The fixed cumulative dividends will be $1.71500 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**
23 Feb 22	$0.3408125
29 Apr 22	$0.3408125
2 Aug 22	$0.3408125
28 Oct 22	$0.3408125
28 Feb 23	$0.3408125
28 Apr 23	$0.3408125
2 Aug 23	$0.3408125
31 Oct 23	$0.3408125
27 Feb 24	$0.4287500
30 Apr 24	$0.4287500
30 Jul 24	$0.4287500
29 Oct 24	$0.4287500
25 Feb 25	$0.4287500

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 June 30, 2023. The fixed cumulative dividends will be $1.3095 per share per annum during this five-year period.

On June 30, 2023, the annual fixed dividend rate on the Series 5 Shares was reset pursuant to their terms to 6.631% for the next five-year period ending June 30, 2028. The fixed cumulative dividends will be $1.65775 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**
23 Feb 22	$0.327375
29 Apr 22	$0.327375
2 Aug 22	$0.327375
28 Oct 22	$0.327375
28 Feb 23	$0.327375
28 Apr 23	$0.327375
2 Aug 23	$0.4144375
31 Oct 23	$0.4144375
27 Feb 24	$0.4144375
30 Apr 24	$0.4144375
30 Jul 24	$0.4144375
29 Oct 24	$0.4144375
25 Feb 25	$0.4144375

The Series 9 Shares paid 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.

On September 30, 2022, the Company redeemed all of the issued and outstanding Series 9 Shares at a price of $25.00 per share for an aggregate total of $150 million.

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**
23 Feb 22	$0.359375
29 Apr 22	$0.359375
2 Aug 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.

On June 30, 2024, the Company redeemed all of the issued and outstanding Series 11 Shares at a price of $25.00 per share (Redemption Price) for an aggregate total of $150 million, less any tax required to be deducted and withheld by the Company. As June 30, 2024 was not a business day payment of the Redemption Price for the share redemption occurred on July 2, 2024.

The following dividends have been declared on the Series 11 Shares for the three most recently completed financial years::

Dividends Declared	
Declaration Date	**Dividend per Share**
23 Feb 22	$0.359375
29 Apr 22	$0.359375
2 Aug 22	$0.359375
28 Oct 22	$0.359375
28 Feb 23	$0.359375
28 Apr 23	$0.359375
2 Aug 23	$0.359375
31 Oct 23	$0.359375
27 Feb 24	$0.359375
30 Apr 24	$0.359375

Dividend Reinvestment Plan

On July 30, 2020, the Company reinstated the DRIP which was launched on January 1, 2012. 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.

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 Toronto Stock Exchange 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.

On August 1, 2023, the Company reinstated the DRIP. Eligible shareholders were entitled to participate in the DRIP commencing with the Company's third quarter 2023 cash dividend. Shareholders that were enrolled in the DRIP upon suspension in December 2021, 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 1% to the average closing price on the Toronto Stock Exchange for the 10 trading days immediately preceding the applicable dividend payment date.

Since the Company's DRIP was introduced and as of the date of this AIF, 9,201,833 Common Shares have been issued pursuant to the DRIP at a weighted average price of $30.78. 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, 2024, there were 138,979,428 Common Shares, 5 million Series 1 Shares, 6 million Series 3 Shares, 8 million Series 5 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.

Subscription Receipts

On November 28, 2023, the Company entered into an agreement with a syndicate of underwriters to issue 8,231,000 subscription receipts, on a bought deal basis, at an issue price of $36.45 per subscription receipt, for total gross proceeds of approximately $300 million. Additionally, the Company entered into a subscription agreement to issue 2,745,000 subscription receipts to Alberta Investment Management Corporation on a private placement basis for gross proceeds of approximately $100 million. See "General Development of the Business – Company History – 2023 – Announcing acquisitions of two contracted combined cycle U.S. gas generation facilities and concurrent equity offerings".

Each subscription receipt entitled the holder to one Common Share in connection with the closing of the first to occur of the completion of the acquisition of the Harquahala or La Paloma facility. On February 9, 2024, the Company completed the acquisition of the La Paloma facility and all of the subscription receipts were exchanged for an aggregate of 10,976,000 Common Shares. A Common Share dividend record date occurred on December 29, 2023 while the subscription receipts were outstanding and as such, the Company made a cash dividend equivalent payment to holders of the subscription receipts of $0.6150 per subscription receipt held for a total cash payment by the Company of $6,750,240.

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 paid 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.

On May 15, 2024, the Company announced its intention to redeem all of its 6,000,000 issued and outstanding Series 11 Shares at a price of $25.00 per share for an aggregate total of $150 million, less any tax required to be deducted and withheld by the Company. As all of the Series 11 Shares were redeemed on June 30, 2024.

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 paid 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.

On August 19, 2022, the Company announced its intention to redeem all of its 6,000,000 issued and Series 9 Shares on September 30, 2022 at a price of $25.00 per share for an aggregate total of $150 million, less any tax required to be deducted and withheld by the Company. All of the Series 9 Shares were redeemed on September 30, 2022.

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 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 again had the right to elect to convert all or any part of their Series 5 Shares into Series 6 Shares, subject to certain conditions, on June 30, 2023. Following the conversion deadline on June 15, 2023, 44,106 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, 2023. Effective June 30, 2023, the annual fixed rate for the Series 5 Shares for the next five-year period was reset to 6.631%.

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, 2028 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 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 again had the right to elect to convert all or any part of their Series 3 Shares into Series 4 Shares, subject to certain conditions, on December 31, 2023. Following the conversion deadline on December 18, 2023, 7,157 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, 2023. Effective December 31, 2023, the annual fixed rate for the Series 3 Shares for the next five-year period was reset to 5.5%.

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, 2028 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 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 Shares, subject to certain conditions, on December 31, 2015. Following the conversion deadline on December 16, 2015, 5,000,000 Series 1 Shares remained outstanding and there were no Series 2 Shares issued. 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 September 16, 2024, the Company closed a public offering of unsecured medium term notes in the aggregate principal amount of $600 million (the Notes). The Notes have a coupon rate of 4.831% and mature on September 16, 2031. The Company used the net proceeds to repay, redeem and refinance existing indebtedness, including indebtedness under the Company’s credit facilities, and for general corporate purposes.

On August 15, 2024, the Company announced the approval of amendments to the indenture governing the $350 million 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 1, due September 9, 2082 (Series 1 Notes). These changes allowed for the exchange of all outstanding principal amount of Series 1 Notes for an equal principal amount of new 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 3, due September 9, 2082 (Series 3 Notes). The Series 3 Notes have the same economic terms as the Series 1 Notes, including interest rates and maturity dates, but without the provision for delivery of preferred shares upon the occurrence of certain bankruptcy and related events. Holders will continue to receive interest accrued on the exchanged Series 1 Notes. This note exchange was completed on August 15, 2024, following the execution of the necessary supplemental indentures. The Series 3 Notes will rank equally in right of payment with the $450 million 8.125% Fixed-to-Fixed Subordinated Notes, Series 2, due June 5, 2054. S&P Global Ratings and Morningstar DBRS confirmed the instrument rating of the Series 3 Notes at BB and BB with a Stable trend, respectively.

On June 12, 2024, Capital Power filed its short form base shelf prospectus. The prospectus was filed in reliance upon the "WKSI Blanket Orders", as the Company determined that it qualified as a "well-known seasoned issuer" (WKSI), which exempts qualifying issuers from certain disclosure requirements relating to such final short form base shelf prospectus. Capital Power may from time to time during the 25-month period that this short form base shelf prospectus remains valid offer and issue the following securities or any combination thereof: (i) Common Shares of the Company; (ii) preference shares of the Company; (iii) subscription receipts exchangeable for Common Shares or other securities of the Company; and (iv) debt securities of the Company. In addition, Capital Power 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 $3 billion. All issuances may be made during the 25-month period that the prospectus remains valid.

On June 5, 2024, the Company closed a public offering of Fixed-to-Fixed Subordinated Notes, Series 2, in the aggregate principal amount of $450 million (the Subordinated Notes). The Subordinated Notes have a fixed interest rate of 8.125% and mature on June 5, 2054. The Company used the net proceeds from the sale of the Subordinated Notes to repay certain amounts drawn on the Company’s credit facilities (which include amounts drawn for the acquisition of a 50% interest in New Harquahala Generating Company, LLC, and a 100% interest in CXA La Paloma, LLC, and related expenses, development purposes and in respect of ongoing operations), to redeem all of the Company’s outstanding Series 11 Shares and for general corporate purposes.

On December 15, 2023, Capital Power issued $850 million of senior unsecured MTNs. This offering consisted of $400 million of 5.378% medium term notes maturing on January 25, 2027 and $450 million of 5.973% medium term notes maturing on January 25, 2034. The offering closed on December 15, 2023, pursuant to the New Indenture as supplemented by an eighth supplemental trust indenture and a ninth supplemental trust indenture, respectively, each dated December 15, 2023.

On September 15, 2023, Capital Power issued $350 million of senior unsecured MTNs due on September 15, 2028 with interest payable semi-annually at a rate of 5.816%, pursuant to the New Indenture as supplemented by a seventh supplemental trust indenture dated September 15, 2023.

On September 9, 2022, Capital Power closed a $350 million offering of Fixed-to-Fixed Rate Subordinated Notes, Series 1 due September 9, 2082 (Subordinated Notes), under a trust indenture dated September 9, 2022, between the Company and Computershare Trust Company of Canada, as trustee. The Company intends to allocate an amount equal to the net proceeds from the sale of the Subordinated Notes to finance or refinance new or existing "green" investments that meet the eligibility criteria as described in "Company History – 2022 – Green Financing Framework". Pending such allocation, the Company used the net proceeds from the sale of the Subordinated Notes to redeem the Company's outstanding Cumulative Minimum Rate Reset Preference Shares, Series 9, to repay certain amounts drawn on the Company's credit facilities and for general corporate purposes. Per the prospectus supplement dated August 18, 2022, the Company will pay interest on the Subordinated Notes in equal semi-annual instalments with the first payment on March 9, 2023, from, and including, the date of issue to but excluding September 9, 2032, the Subordinated Notes will bear interest at a rate of 7.95% per annum and on every fifth anniversary of such date thereafter the interest rate on the Subordinated Notes will reset.

In August 2023, the Company posted its Green Bond Report to its website which outlines the allocation of Green Financing proceeds by eligible category. The proceeds from the 2022 green bond offering to projects, which meet the eligible green criteria outlined in the Green Financing Framework have been fully allocated.

On June 16, 2022, Capital Power executed a sixth supplemental trust indenture amending certain terms of the New Indenture for all series of MTNs issued after the date thereof.

On July 20, 2021, Capital Power 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 redeemed all of its outstanding 5.276% MTNs, 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 issued $350 million of senior unsecured MTNs 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 fifth supplemental trust indenture dated October 1, 2020.

On June 1, 2020, Capital Power executed a fourth supplemental trust indenture amending certain terms of the New Indenture for all series of MTNs issued after the date thereof.

On November 8, 2019, Capital Power issued $275 million of senior unsecured MTNs 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 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 issued $300 million of senior unsecured MTNs 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 issued $450 million of senior unsecured MTNs 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 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 MTNs 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 L.P. (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; and (ii) an extendible revolving club credit facility of up to $300 million. Both credit agreements were extended and amended on June 11, 2024 and have a maturity date of July 13, 2029. Prior to that, in July 2021 both credit agreements were transitioned into sustainability linked credit facilities (SLCs). The SLCs currently maintain GHG emissions intensity as its sustainability performance target metric; 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. 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 credit agreements 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 that is not investment grade (investment grade means at least two Debt Ratings from the following Rating Agencies of not lower than "BBB-" from S&P, "BBB(low)" from DBRS, "Baa3" from Moody's and "BBB-" from Fitch (in each case 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's consolidated financial results.

Capital Power has existing Canadian dollar revolving letter of credit demand facilities with various lenders totalling CAD$990 million, in addition, three U.S. dollar revolving letter of credit demand facilities totalling U.S.$300 million.

Ratings

The following credit rating agencies have assigned the below credit ratings to the debt obligations and hybrid instruments of the Company:

Debt Ratings

Capital Power 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.

Hybrid Instrument Ratings

The hybrid instruments are rated two notches below the Company's corporate credit rating as they are deeply subordinated. The Preferred Shares and notes are hybrid securities that combine both debt and equity characteristics which are provided a degree of equity treatment from rating agencies without diluting the ownership interests of their common shareholders and debt treatment from tax authorities whereby the associated interest expense is deductible for income tax purposes. These ratings are intended to provide investors with an independent measure of credit quality of an issue of securities.

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.

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. Pfd-3 ratings generally correspond with issuers with a BBB category or higher reference point. 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 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.

Subordinated Notes Ratings

The fixed-to fixed rate subordinated notes, as described above under "Debt Issuance", have been assigned a rating of BB by DBRS and BB by S&P.

The BB rating category used by DBRS and, in DBRS's view, denotes speculative, non-investment grade credit quality. The capacity for the payment of financial obligations is uncertain and the entity is vulnerable to future events. DBRS measures the characteristics against the attributes of common equity including its subordination to all other creditors, permanence in the capital structure, and tolerance for missed scheduled payments without causing a default or cross-default to debt instruments. DBRS assigned 50% equity treatment to the notes.

The BB rating category used by S&P and, according to the S&P rating system, is regarded as having significant speculative characteristics. While such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions. S&P classifies the notes as having intermediate equity content because of their subordination, permanence, and optional deferability features, in line with their hybrid capital criteria. S&P assigned 50% equity treatment to the notes.

The credit ratings by each of DBRS and S&P is not a recommendation to buy, sell or hold any securities of the Company. 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 at any time 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.

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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 2024 CPX Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	38.46	36.09	36.96	10,774,984
February	38.80	35.55	38.35	7,329,753
March	39.43	37.31	38.21	7,823,483
April	38.31	35.19	35.93	8,958,802
May	39.45	33.90	39.33	9,597,977
June	41.99	38.70	38.99	14,937,125
July	43.50	38.325	42.67	10,465,040
August	45.15	42.18	44.95	6,487,557
September	50.88	44.31	49.17	11,347,947
October	56.82	49.20	56.47	11,145,142
November	64.39	54.83	62.28	9,324,632
December	68.73	58.8	63.72	17,584,693

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 2024 CPX.PR. A Trading Statistics

Month	**Share Price**			**Volume Traded**
	High	**Low**	**Close**	
January	14.25	12.93	14.25	22,598.00
February	14.25	13.88	14.09	21,746.00
March	15.44	14.05	14.99	13,845.00
April	14.72	14.16	14.65	17,694.00
May	15.15	14.63	15.00	91,392.00
June	15.55	14.65	15.55	26,663.00
July	15.35	14.73	15.20	156,311.00
August	15.64	14.84	15.27	26,721.00
September	15.36	15.10	15.31	19,267.00
October	15.65	15.28	15.47	41,609.00
November	16.88	15.41	16.88	29,646.00
December	17.25	16.60	17.25	23,165.00

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 2024 CPX.PR. C Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	22.90	22.01	22.43	125,418.00
February	22.69	22.36	22.62	85,843.00
March	22.73	21.98	22.25	75,485.00
April	22.90	21.63	22.11	202,648.00
May	23.88	21.90	23.88	204,520.00
June	23.94	21.05	23.06	263,567.00
July	23.74	22.80	23.22	381,933.00
August	25.00	23.05	24.64	147,871.00
September	24.83	23.89	24.39	191,583.00
October	24.51	24.08	24.50	126,982.00
November	24.78	24.23	24.66	126,154.00
December	24.95	24.50	24.85	134,311.00

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 2024 CPX.PR. E Trading Statistics

Month	Share Price			Volume Traded
	High	Low	Close	
January	22.42	21.49	$21.85	65,389
February	22.14	21.60	$22.06	91,961
March	22.40	21.88	$22.24	33,450
April	22.45	21.46	$21.75	105,770
May	23.11	21.50	$22.95	250,891
June	23.14	20.23	$22.26	86,901
July	22.92	22.00	$22.54	172,120
August	24.41	22.36	$24.00	79,872
September	24.33	23.25	$23.80	67,866
October	23.98	22.88	$23.50	47,856
November	23.98	23.26	$23.98	53,785
December	24.19	23.55	24.03	44,550

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 the date of this AIF:

Name, Province / State and Country of Residence	Director Since	Office Held[(1)(2)] Committee Membership[(3)]	Principal Occupation During Past Five Years
Gary Bosgoed Edmonton, Alberta, Canada Date of Birth: September 1958 Shares held:[(4)] Nil	June 1, 2022	Director **Committees:** HSE PCG	President and Chief Executive Officer of Bosgoed Project Consultants Ltd. from July 2015
Avik Dey Edmonton, Alberta, Canada Date of Birth: February 1978 Shares held:[(4)] Nil	May 8, 2023	Director	President and Chief Executive Officer, Capital Power Corporation from May 2023; prior thereto, Co-Head, Energy Business at The Carlyle Group Inc. from May 2022 to November 2022; prior thereto, Senior Vice President and Chief Financial Officer, NOVA Chemicals Corporation from July 2021 to May 2022; prior thereto, Managing Director and Head of Energy and Resources, Real Assets, Canada Pension Plan Investment Board from September 2014 to June 2021
Jill Gardiner Vancouver, British Columbia, Canada Date of Birth: December 1958 Shares held:[(4)] Common Shares – 10,827	May 25, 2015	Director and Chair **Committees**:[(5)] Audit PCG HSE	Professional Corporate Director

Name, Province / State and Country of Residence	Director Since	Office Held[(1)(2)] Committee Membership[(3)]	Principal Occupation During Past Five Years
Carolyn Graham Edmonton, Alberta, Canada Date of Birth: June 1964 Shares held:[(4)] Common Shares – 1,240	August 2, 2023	Director **Committees:** Audit PCG	Professional director since October 2022; prior thereto held the following positions at Canadian Western Bank: Senior Executive Vice President (EVP), Program Synergy from April 2022; EVP from November 2021; EVP and Chief Risk Officer from December 2020; EVP and Chief Financial Officer from October 2014
Kelly Huntington Indianapolis, Indiana, USA Date of Birth: September 1975 Shares held:[(4)] Nil	June 3, 2015	Director **Committees**: PCG (Chair) Audit	Senior Vice President and Chief Financial Officer from February 2023 and Senior Vice President from January 2023 to February 2023, MYR Group Inc.; prior thereto professional director from January 2022 to January 2023; prior thereto Senior Vice President and Chief Financial Officer, USIC, LLC, from November 2019 to January 2022
Barry Perry St John's, Newfoundland and Labrador, Canada Date of Birth: September 1964 Shares held:[(4)] Common Share – 26,000	March 1, 2021	Director **Committees:** Audit (Chair) PCG	Professional director from March 2021; prior thereto President and Chief Executive Officer of Fortis Inc. from January 2015 to December 2020
Jane Peverett West Vancouver, British Columbia, Canada Date of Birth: September 1958 Shares held:[(4)] Common Share – 2,000	March 1, 2019	Director **Committees:** PCG HSE	Professional director
Robert L. Phillips Anmore, British Columbia, Canada Date of Birth: January 1951 Shares held:[(4)]	April 26, 2019	Director **Committees:** Audit HSE	President of R.L. Phillips Investments Inc., a private investment firm since 2001

Name, Province / State and Country of Residence	**Director Since**	**Office Held[(1)(2)]** **Committee Membership[(3)]**	**Principal Occupation During Past Five Years**
Common Share – 6,603			
Neil H. Smith Indian River Shores, Florida, USA Date of Birth: October 1964 Shares held:[(4)] Nil	May 15, 2024	Director **Committees:** Audit HSE	Professional director since December 2024; prior thereto, Chief Executive Officer of Vanguard Renewables LLC from September 2021 to November 2024; prior thereto, President, Rev Renewables from July 2021 to August 2021; prior thereto, Executive-in-Residence, LS Power from April 2021 to June 2021; prior thereto PJM Interconnect Board of Managers from May 2018 to April 2021
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
George Williams Naperville, Illinois, USA Date of Birth: September 1961 Shares held:[(4)] Nil	May 15, 2024	Director **Committees:** PCG HSE	Consultant at PMI Energy Solutions from December 2023; prior thereto Chairman and CEO of PMI Energy Solutions from February 2011 to November 2023

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, 2024, the number of Common Shares, Series 1 Shares, Series 3 Shares and Series 5 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.

The Board has determined that all the directors, except for Avik Dey, 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. Avik Dey is not considered independent as he is the President and Chief Executive Officer of the Company.

<u>Executive Officers</u>[1]

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 the date of this AIF:

Name, Province / State and Country of Residence	**Officer Since**	**Office Held**	**Principal Occupation During the last 5 Years**
Avik Dey Edmonton, Alberta, Canada Date of Birth: February 1978 <u>Shares held:</u>[2] Nil	May 8, 2023	President and Chief Executive Officer from May 8, 2023	President and Chief Executive Officer, Capital Power Corporation from May 2023; prior thereto, Co-Head, Energy Business at The Carlyle Group Inc. from May 2022 to November 2022; prior thereto, Senior Vice President and Chief Financial Officer, NOVA Chemicals Corporation from July 2021 to May 2022; prior thereto, Managing Director and Head of Energy and Resources, Real Assets, Canada Pension Plan Investment Board from September 2014 to June 2021
Sandra Haskins Edmonton, Alberta, Canada Date of Birth: December 1959 <u>Shares held</u>:[2] Common Shares – 11,183	July 30, 2020	Senior Vice President, Finance and Chief Financial Officer from 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
Jacquelyn Pylypiuk St. Albert, Alberta, Canada Date of Birth: February 1969 <u>Shares held:</u>[2] Common Shares – 16,029	April 2015	Senior Vice President, Technology & Chief People and Culture Officer from August 29, 2023	Senior Vice President, Technology & Chief People and Culture Officer from August 29, 2023; prior thereto Senior Vice President, People, Culture and Technology from July 30, 2020; prior thereto Vice President, Human Resources, Capital Power Corporation, from April 2015

Name, Province / State and Country of Residence	Officer Since	Office Held	Principal Occupation During the last 5 Years
May Wong Sturgeon County, Alberta, Canada Date of Birth: August 1981 <u>Shares held:</u>(2) Common Shares – 729	August 29, 2023	Senior Vice President, Energy Markets and Low Carbon Solutions from December 4, 2024	Senior Vice President, Energy Markets and Low Carbon Solutions from December 4, 2024, prior thereto, Senior Vice President, Strategy, Planning & Sustainability from August 29, 2023; prior thereto Vice President, Strategy, Forecasting & Sustainability from May 2022; prior thereto Vice President, Market Assessment & Analytics from September 2019; prior thereto Director, Market Assessment & Forecasting
Jason Comandante Calgary, Alberta, Canada Date of Birth: November 1979 <u>Shares held:</u>(2) Common Shares – 9,383	August 29, 2023	Senior Vice President, Head of Canada from August 29, 2023	Senior Vice President, Head of Canada from August 29, 2023; prior thereto Vice President, Commercial Services, Canada West from July 2020; prior thereto Vice President, Regulatory & Environmental Policy from August 2017
Pauline McLean Calgary, Alberta, Canada Date of Birth: August 1977 <u>Shares held:</u>(2) Nil	August 29, 2023	Senior Vice President, External Relations and Chief Legal Officer from September 11, 2023	Senior Vice President, External Relations & Chief Legal Officer from September 11, 2023; prior thereto Vice President, Law, General Counsel & Corporate Secretary at Alberta Electric System Operator from October 2019
Steve Wollin Edmonton, Alberta, Canada Date of Birth: June 1966 <u>Shares held:</u>(2) Common Shares – 1,038	August 29, 2023	Senior Vice President, Operations from August 29, 2023	Senior Vice President, Operations from August 29, 2023; prior thereto Vice President, Operations, Gas and Renewables from April 2018

Notes:
(1) Bryan DeNeve served as Senior Vice President, Chief Commercial Officer, until January 19, 2025.
(2) Represents as of December 31, 2024 the number of Common Shares, Series 1 Shares, Series 3 Shares and Series 5 Shares, as applicable, beneficially owned, or controlled or directed, directly or indirectly, by such persons.

As at December 31, 2024, 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, 46,670 Common Shares ($63.72 per share as at the close of trading on December 31, 2024 for a value of $2,973,812.40), which is less than 1% of the issued and outstanding Common Shares.

As at December 31, 2024, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 85,032 Common Shares ($63.72 per share as at the close of trading on December 31, 2024 for a value of $5,418,239.04), 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, 2024, 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 company 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.

Jill Gardiner was a director of Trevali Mining Corporation (Trevali) between July 2019 and September 2022. On August 19, 2022, Trevali received an Initial Order for creditor protection from the British Columbia Supreme Court under the Companies' Creditors Arrangement Act (CCAA) for an initial period of ten days. The Initial Order was subsequently extended to October 6, October 18th, and finally December 16, 2022 to allow Trevali to restructure its business and financial affairs. On December 16, 2022, Trevali announced a winning bid under the Sales and Solicitation Process and disclosed that the company would be seeking Court approval of the proposed transaction. The transaction was approved by the Supreme Court of British Columbia on December 21, 2022 and was completed on June 27, 2023. On June 28, 2023 the Court appointed monitor was granted enhanced powers in the CCAA proceedings with respect to the Company's business and affairs.

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.

Keith Trent is a director of Edison International. Edison International’s subsidiary, Southern California Edison has an offtake agreement related to the La Paloma facility.

Jane Peverett is a director of Canadian Pacific Kansas City Limited (“CPKC), NW Natural and Suncor Energy Inc. (“Suncor”). CPKC may provide transportation services to Capital Power. NW Natural may provide natural gas to Capital Power generators located in Oregon or Washington states in the future. Suncor sells electricity into the Alberta market.

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.

Claim Against Province of Alberta and Balancing Pool

In 2015, pursuant to a complaint regarding the AESO's 2005 loss factor calculation methodology (LFM), the AUC determined that the LFM did not comply with applicable regulations. The LFM is used to calculate generator-specific line loss factors and forms the basis for certain transmission charges paid by Alberta generators. In December 2017 the AUC determined a revised LFM for determining retroactive adjustments back to January 2006. Implementation of the historic LFM adjustments by the AESO occurred over the course of 2018 – 2020 and, following a further decision of the AUC on July 9, 2020, the AESO was directed to and issued three separate invoices for the various historic years. The AUC directed the AESO to issue the adjustment invoices to the entities that held the applicable system transmission agreements with the AESO at the time the line losses occurred, however, the AUC expressly did not determine the matter of liability for payment given the fact some agreements had changed hands in the intervening periods.

In December 2016, Capital Power had entered into an agreement with the Province of Alberta pursuant to which the interests of Capital Power as the PPA Buyer in respect of the Sundance C PPA were wholly transferred to and assumed by the Balancing Pool. In January 2017, in furtherance of the agreement with the Province of Alberta and the transfer of the Sundance C PPA to the Balancing Pool, the system transmission agreements between Capital Power and the AESO relating to the Sundance C PPA were wholly transferred to and assumed by the Balancing Pool pursuant an assignment, assumption and novation agreement among Capital Power, the Balancing Pool and the AESO.

The AESO completed the primary invoicing process for all three tranches of historic line-loss adjustment invoices relating to the Sundance C PPA covering the years 2006-2016 and issued them to Capital Power. Capital Power forwarded the invoices to the Balancing Pool and demanded that it make payment of them. The Balancing Pool refused to make payment. Capital Power made payment to the AESO of the invoices under protest 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.

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. Alberta has not taken steps in accordance with its agreement with Capital Power to ensure the Balancing Pool complied with its obligations upon the transfer of the Sundance C PPA to it. 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 King'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. In September 2024 Capital Power filed a Partial Discontinuance of Claim discontinuing its claim only as against the AESO.

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 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 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 is taking all appropriate actions to defend itself.

Genesee Repowering

A dispute has arisen between the Company and the contractor regarding construction work on the Genesee Repowering Project. The parties are actively participating in an agreed-upon mediation process to resolve the claims by both parties. The Company has withheld payments pending the resolution of the dispute which is at a preliminary stage. The Company is still reviewing the claims and at this time the outcome of the mediation process is uncertain.

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.sedarplus.ca.

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 29, 2022 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 25th, 2025, the Board resolved to continue the Rights Plan. If the Rights Plan is approved at the 2025 annual meeting of shareholders of Capital Power, the Rights Plan will expire at the close of business on the date of the 2028 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 2025 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 approximately $2.7 million from each of the payments from 2017 through 2024. 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, 2024, the Audit Committee was composed of Barry Perry (Chair), Carolyn Graham, Kelly Huntington, Robert Phillips, Neil H. Smith 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
Barry Perry	• Chartered 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 • member of the audit committees of Royal Bank of Canada and CPP Investments
Carolyn Graham	• Chartered Professional Accountant • Fellow of Institute of Chartered Professional Accountants of Alberta • former Chief Financial Officer of Canadian Western Bank, TSX listed, federally regulated Schedule 1 bank • former chair of audit committee for public REIT, as well as numerous non-profits • holds a Bachelor of Commerce from the University of Alberta
Kelly Huntington	• current Senior Vice President and Chief Financial Officer of MYR Group Inc. • former Senior Vice President and Chief Financial Officer of USIC • former Senior Vice President of Enterprise Strategy for OneAmerica Financial Partners which included responsibility for internal audit • former 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, is a Chartered Financial Analyst, and has the NACD. DC designation
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 • former chair and member of the audit committee of Canadian Western Bank • former 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 former director of the Institute of Corporate Directors and chair of its audit committee
Neil H. Smith	• former Chief Executive Officer of Vanguard Renewables • former Chief Executive Officer of Intergen, Inc. • former director of The Wood Group PLC and PJM Interconnection • holds a BA in Political Science from Emory University • holds an MBA from Harvard Business School

AC Member	Relevant Education and Experience
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. There were no non-audit related services which required approval in 2024.

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, 2024 in respect of the Company and the Company's subsidiaries were approximately $2.4 million as detailed below.

	Twelve Months Ended December 31, 2024 ($ Millions)	Twelve Months Ended December 31, 2023 ($ Millions)
Audit fees	2.1	1.5
Audit related fees	0.3	0.4
Tax fees	-	-
All other fees	-	-
Total	**2.4**	**1.9**

Audit fees – Audit fees billed are for professional services rendered for the audit and review of the financial statements of the Company and its subsidiaries 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. During fiscal years 2024 and 2023, the services provided in this category include sustainability assurance engagements and French translation work performed in relation to securities filings engagements.

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 HSE 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, 2024 were as follows:

PCG Committee

Kelly Huntington, Chair
Gary Bosgoed
Carolyn Graham
Barry Perry
Jane Peverett
George Williams
Jill Gardiner (ex-officio)

Health, Safety, and Environment Committee

Keith Trent, Chair
Gary Bosgoed
Jane Peverett
Robert Phillips
Neil H. Smith
George Williams
Jill Gardiner (ex-officio)

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR+ at www.sedarplus.ca 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, 2024.

The "Risks and Risk Management" section of the Company's 2024 Integrated Annual Report for the year ended December 31, 2024 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 integrated annual report, including the annual audited financial statements, the notes thereto, management's discussion and analysis, the earnings press release and the Corporation's annual information form, including any report or opinion or independent external assurance 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. Review the process used by Management to measure publicly disclosed progress toward the achievement of material non-financial, sustainability related performance metrics to ensure accuracy and reasonableness.

7. 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.

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

9. 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.

10. 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.

11. 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.

12. Discuss 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.

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

14. 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.

15. 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.

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

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

18. 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.

19. 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.

20. 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.

21. Monitor compliance with the Corporation's Code of Conduct (the “Code of Conduct”) and ensure Management Compliance Certificates have been executed.

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

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

24. 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.

25. 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.

26. 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 a summary of all internal audit reports issued in relation thereto.

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

28. 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.

29. Annually review the performance, budget and independence of the internal audit function and direct the Senior Vice President, Finance and Chief Financial Officer (or their delegate) to make any changes necessary.

30. 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.

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

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

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

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

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

36. 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.

37. 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.

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

39. Review at least every three years the Code of Conduct and recommend any required material changes to the Board.

40. Review annually these terms of reference and the Corporation’s Disclosure and Insider Trading Policy regarding public disclosure of material information and insider trading and recommend any required material changes to the PCG Committee for further recommendation to the Board.

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

42. 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.

43. 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 <u>not</u> 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.