Capital Power Corporation
10423 – 101 Street NW
Suite 1200
Edmonton, AB T5H 0E9

For immediate release | October 31, 2022

# Capital Power reports strong third quarter results and increases its 2022 financial guidance for a second consecutive quarter

**EDMONTON, Alberta – October 31, 2022 –** Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended September 30, 2022.

### Financial Highlights

- Generated net cash flows from operating activities of $370 million and adjusted funds from operations (AFFO) of $328 million
- Generated net income of $31 million and a record quarter for adjusted EBITDA of $383 million
- Increased 2022 annual financial guidance for adjusted EBITDA to $1,300 million to $1,340 million (original guidance of $1,110 million to $1,160 million) and AFFO to $770 million to $810 million (original guidance of $580 million to $630 million)

### Strategic Highlights

- Continued executing on Company's natural gas strategy by completing the acquisition of the Midland Cogeneration Venture Limited Partnership (Midland Cogen) facility, the largest gas-fired cogeneration facility in North America, where Capital Power and Manulife Investment Management each own a 50% interest in the 1,633 megawatt facility. Capital Power is responsible for the operations and maintenance and asset management of the facility.
- Completed a $350 million offering of green hybrid subordinated notes, the first ever in Canada and represents the Company's first green offering. An amount equal to the net proceeds of the offering will be used to finance or refinance new or existing green investments that meet the eligibility criteria as described in the Company's Green Financing Framework.

"Quarterly results in 2022 continue to exceed management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "In the third quarter, we had strong operating performance from our facilities with a 96% average availability and higher generation for the fleet. Notably, our Alberta commercial facilities delivered exceptional performance from high Alberta power prices that averaged $221 per megawatt hour contributing to a record quarter for adjusted EBITDA of $383 million."

"Based on outstanding performance across the fleet, we have once again increased our 2022 financial guidance with revised guidance ranges significantly exceeding the top end of our original targets," stated Mr. Vaasjo.

"In August 2022, we released our inaugural Green Financing Framework (Framework) under which we will issue green bonds and green loans - the first of which was $350 million in green hybrid subordinated notes," said Sandra Haskins, Senior Vice-President, Finance and Chief Financial Officer. "The Framework reflects our commitment to allocate capital to wind, solar and storage projects that align with the Company's sustainability targets and support our strategy to be net-zero by 2050.

## Operational and Financial Highlights[1]

| (unaudited, $ millions, except per share amounts) | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | 2022 | 2021 | 2022 | 2021 |
| Electricity generation (Gigawatt hours) | 6,993 | 6,103 | 20,524 | 16,708 |
| Generation facility availability | 96% | 91% | 94% | 90% |
| Revenues and other income | 786 | 377 | 2,000 | 1,318 |
| Adjusted EBITDA [2] | 383 | 286 | 1,050 | 830 |
| Net income [3] | 31 | 38 | 227 | 156 |
| Net income attributable to shareholders of the Company | 34 | 40 | 236 | 163 |
| Basic earnings per share ($) | 0.21 | 0.23 | 1.76 | 1.10 |
| Diluted earnings per share ($) | 0.20 | 0.23 | 1.75 | 1.09 |
| Normalized earnings attributable to common shareholders [2] | 146 | 63 | 342 | 166 |
| Normalized earnings per share ($) [2] | 1.25 | 0.55 | 2.94 | 1.50 |
| Net cash flows from operating activities | 370 | 347 | 893 | 682 |
| Adjusted funds from operations [2] | 328 | 206 | 708 | 456 |
| Adjusted funds from operations per share ($) [2] | 2.81 | 1.78 | 6.08 | 4.12 |
| Purchase of property, plant and equipment and other assets, net | 224 | 176 | 503 | 424 |
| Dividends per common share, declared ($) | 0.5800 | 0.5475 | 1.6750 | 1.5725 |

1 The operational and financial highlights in this press release should be read in conjunction with the Management's Discussion and Analysis and the unaudited condensed interim financial statements for the nine months ended September 30, 2022.

2 Earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emissions credits (adjusted EBITDA), normalized earnings attributable to common shareholders and adjusted funds from operations (AFFO) are used as non-GAAP financial measures by the Company. The Company also uses normalized earnings per share and AFFO per share which are non-GAAP ratios. These measures and ratios do not have standardized meanings under GAAP and are, therefore, unlikely to be comparable to similar measures used by other enterprises. See Non-GAAP Financial Measures and Ratios.

3 Includes depreciation and amortization for each of the three months ended September 30, 2022 and 2021 of $133 million, and for the nine months ended September 30, 2022 and 2021 of $414 million and $402 million, respectively. Forecasted depreciation and amortization for the remainder of 2022 is $136 million for the fourth quarter.

## Significant Events

### Preferred shares, Series 9, redemption

On September 30, 2022, the Company redeemed all of its 6 million issued and outstanding 5.75% Cumulative Minimum Rate Reset Preference Shares, Series 9 (Series 9 Shares) at a price of $25.00 per share for gross payments of $150 million. On September 30, 2022, the Company also paid the final declared quarterly dividend of $0.3594 per Series 9 Share.

### Acquisition of Midland Cogeneration Venture

On September 23, 2022, Capital Power and Manulife Investment Management, on behalf of the Manulife Infrastructure Fund II and its affiliates completed its previously announced acquisition of 100% interest in MCV Holding Company LLC through its joint venture partnership, MCV Partners LLC. MCV Holding Company LLC owns 100% of Midland Cogeneration Venture Limited Partnership (Midland Cogen), a 1,633 MW natural gas combined-cycle cogeneration facility.

Capital Power's investment for its 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 its share of the transaction using cash on hand and its existing credit facilities. The Company expects to finalize the working capital adjustment in the fourth quarter of 2022. Due to the proximity of the acquisition's closing date to September 30, 2022, the equity income from MCV Partners LLC was not material in the quarter. Substantially all of the underlying assets and liabilities of Midland Cogen relate to the cogeneration facility and the project level debt. Capital Power is responsible for operations and maintenance and asset management for which it will receive an annual management fee.

Located in Michigan, Midland Cogen, the largest gas-fired cogeneration facility in North America, is a critical asset to support grid reliability during the transition to renewables and is well-positioned, given anticipated market conditions, for recontracting beyond 2030.

The acquisition supports Capital Power's strategy of acquiring mid-life contracted natural gas assets that are strategically positioned within their power markets. Acquisition highlights include:

- Capital Power's share of expected average adjusted EBITDA of US$59 million per year (ranging from US$85 million in 2023 and declining to US$45 million in 2027).
- based on the actual financing, the 5-year average accretion for Capital Power's AFFO is expected to be US$0.30 per share, reflecting a 7% increase, or an average AFFO of US$35 million per year during the years 2023-2027.
- power purchase agreement with Consumers Energy (rated Baa1/A-/A-) for 1,240 MW of capacity to 2030
- steam and electricity purchase agreement with Corteva Agriscience (rated NA/A-/A) and Dow Silicones (rated Baa2/BBB/BBB+) to 2035.
- approximately 15% (243 MW) of uncontracted capacity is available to sell into the MISO Zone 7 market.
- located on 1,200 acres leased from Consumers Energy. Current layout and additional space allow for additional turbines, battery installation or a hybrid opportunity.

## $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 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 indenture governing the Subordinated Notes.

This is the first ever Green hybrid subordinated debt security in Canada and represents the Company's first green offering under Capital Power's short form base prospectus dated June 10, 2022, as supplemented by a prospectus supplement dated August 18, 2022. 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 the Company's Green Financing Framework (see Significant Events).

## Green Financing Framework

On August 15, 2022, the Company released its inaugural Green Financing Framework (Framework) under which the Company will issue green bonds and green loans (Green Financing). The 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 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 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 Framework, and are aligned with the United Nations Sustainable Development Goals: affordable and clean energy; industry, innovation and infrastructure; and climate action.

Until the Green Financing issued under this Framework is fully allocated, Capital Power will report publicly on the use of the proceeds within one year of issuance and annually thereafter. Both the Allocation and Impact Reports will be posted on the Company's website. An external verification of the Allocation Report will be provided by an independent external auditor on an annual basis until the complete allocation of proceeds.

Sustainalytics reviewed the Framework and provided a second-party opinion confirming that the Framework is credible and impactful and aligns with the Green Bond Principles 2021 and Green Loan Principles 2021. BMO Capital Markets advised Capital Power on the development of the Framework as lead structuring agent.

## Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 31, 2022 at 9:00 am (MT) to discuss the third quarter financial results. The conference call dial-in number is:

(800) 319-4610 (toll-free from Canada and USA)

Interested parties may also access the live webcast on the Company's website at www.capitalpower.com with an archive of the webcast available following the conclusion of the analyst conference call.

## Non-GAAP Financial Measures and Ratios

The Company uses (i) adjusted EBITDA, (ii) AFFO, and (iii) normalized earnings attributable to common shareholders as financial performance measures.

The Company also uses AFFO per share and normalized earnings per share as performance measures. These measures are non-GAAP ratios determined by applying AFFO and normalized earnings attributable to common shareholders, respectively, to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

### Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations such as impairments, foreign exchange gains or losses and gains or losses on disposals are excluded from the adjusted EBITDA measure.

A reconciliation of adjusted EBITDA to net income (loss) is as follows:

| (unaudited, $ millions) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| Revenues and other income | 786 | 713 | 501 | 672 | 377 | 387 | 554 | 516 |
| Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense | (543) | (429) | (178) | (506) | (162) | (176) | (264) | (321) |
| Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel | 136 | 28 | 18 | 123 | 66 | 24 | 7 | 19 |
| Adjusted EBITDA from joint ventures [1] | 4 | 7 | 7 | 5 | 5 | 6 | 6 | 6 |
| **Adjusted EBITDA** | **383** | **319** | **348** | **294** | **286** | **241** | **303** | **220** |
| Depreciation and amortization | (133) | (139) | (142) | (137) | (133) | (132) | (137) | (122) |
| Unrealized changes in fair value of commodity derivatives and emission credits | (136) | (28) | (18) | (123) | (66) | (24) | (7) | (19) |
| Impairment (losses) reversals | - | - | - | (52) | (8) | 2 | - | (13) |
| (Losses) gains on disposals and other transactions | (3) | (1) | - | 6 | 31 | (3) | 2 | - |
| Foreign exchange (loss) gain | (12) | (7) | 1 | (1) | (7) | (2) | 1 | 5 |
| Net finance expense | (40) | (35) | (37) | (44) | (43) | (46) | (41) | (57) |
| Finance expense and depreciation expense from joint ventures [1] | (4) | (1) | - | (4) | (4) | (5) | - | (4) |
| Income tax expense | (24) | (31) | (33) | (8) | (18) | (14) | (20) | (9) |
| **Net income (loss)** | **31** | **77** | **119** | **(69)** | **38** | **17** | **101** | **1** |
| | | | | | | | | |
| **Net income (loss) attributable to:** | | | | | | | | |
| Non-controlling interests | (3) | (3) | (3) | (4) | (2) | (3) | (2) | (2) |
| Shareholders of the Company | 34 | 80 | 122 | (65) | 40 | 20 | 103 | 3 |
| **Net income (loss)** | **31** | **77** | **119** | **(69)** | **38** | **17** | **101** | **1** |

[1] Total income from joint ventures as per the Company's consolidated statements of income.

## Adjusted funds from operations and adjusted funds from operations per share

AFFO and AFFO per share are measures of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, the repayment of debt and the payment of common share dividends.

AFFO represents net cash flows from operating activities adjusted to:

- remove timing impacts of cash receipts and payments that may impact period-to-period comparability which include deductions for net finance expense and current income tax expense, the removal of deductions for interest paid and income taxes paid and removing changes in operating working capital,
- include the Company's share of the AFFO of its joint venture interests and exclude distributions received from the Company's joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from off-coal compensation that will be received annually,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only the Company's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends,
- exclude the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty, and
- include net expected cash outflows for the Company's share of Line Loss Rule (LLR) Proceeding amounts in the period each tranche is paid by the Company.

A reconciliation of net cash flows from operating activities to adjusted funds from operations is as follows:

| (unaudited, $ millions) | **Three months ended September 30** | | **Nine months ended September 30** | |
|---|---|---|---|---|
| | **2022** | **2021** | **2022** | **2021** |
| **Net cash flows from operating activities per condensed interim consolidated statements of cash flows** | **370** | **347** | **893** | **682** |
| Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows: | | | | |
| Interest paid | 22 | 37 | 76 | 98 |
| Realized gains on settlement of hedged interest rate derivatives | (27) | - | (27) | (12) |
| Change in fair value of derivatives reflected as cash settlement | 15 | 6 | 60 | 17 |
| Distributions received from joint ventures | (4) | (3) | (6) | (8) |
| Miscellaneous financing charges paid [1] | 1 | 1 | 5 | 4 |
| Income taxes paid (recovered) | 7 | (18) | 24 | (13) |
| Change in non-cash operating working capital | (46) | (120) | (151) | (105) |
| | (32) | (97) | (19) | (19) |
| Net finance expense [2] | (20) | (29) | (80) | (93) |
| Current income tax expense [3] | (15) | (3) | (39) | (19) |
| Sustaining capital expenditures [4] | (20) | (52) | (75) | (99) |
| Preferred share dividends paid | (9) | (12) | (29) | (38) |
| Cash received for off-coal compensation | 50 | 50 | 50 | 50 |
| Remove tax equity interests' respective shares of adjusted funds from operations | (1) | (1) | (9) | (7) |
| Adjusted funds from operations from joint ventures | 5 | 3 | 16 | 12 |
| Line Loss Rule Proceeding [5] | - | - | - | (13) |
| **Adjusted funds from operations** | **328** | 206 | **708** | 456 |
| Weighted average number of common shares outstanding (millions) | **116.7** | **115.5** | **116.4** | **110.7** |
| **Adjusted funds from operations per share ($)** | **2.81** | **1.78** | **6.08** | **4.12** |

1 Included in other cash items on the condensed interim consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges and non-cash implicit interest on tax equity investment structures.

3 For the three and nine months ended September 30, 2021, excludes current income tax expenses of $6 million and $14 million, respectively, related to the Genesee 3 and Keephills 3 swap transaction as these amounts are considered investing activities.

4 Includes sustaining capital expenditures net of partner contributions of $2 million and $4 million for the three and nine months ended September 30, 2022, respectively, compared with $1 million and $8 million for the three and nine months ended September 30, 2021, respectively.

5 Consistent with the Company's definition of AFFO described above pertaining to the LLR Proceeding, AFFO for the three months and nine months ended September 30, 2021 is impacted only by the Company's net obligations related to the 2006-2009 and 2010–2013 invoice tranches (see Contingent Liabilities, Other Legal Matters and Provisions).

### Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings attributable to common shareholders and normalized earnings per share are based on net income (loss) attributable to shareholders of the Company according to GAAP and adjusted for items that are not reflective of performance in the period such as unrealized fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange gain or loss on the revaluation of U.S. dollar denominated debt. The adjustments, shown net of tax, consist of unrealized fair value changes on financial instruments that are not necessarily indicative of future actual realized gains or losses, non-recurring gains or losses, or gains or losses reflecting corporate structure decisions.

| (unaudited, $ millions except per share amounts and number of common shares) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| **Basic earnings (loss) per share ($)** | **0.21** | **0.59** | **0.96** | **(0.67)** | **0.23** | **0.05** | **0.83** | **(0.09)** |
| **Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)** | **34** | **80** | **122** | **(65)** | **40** | **20** | **103** | **3** |
| Preferred share dividends including Part VI.1 tax | (10) | (11) | (10) | (13) | (13) | (14) | (14) | (13) |
| Earnings (loss) attributable to common shareholders | 24 | 69 | 112 | (78) | 27 | 6 | 89 | (10) |
| Unrealized changes in fair value of derivatives [1] | 110 | 14 | (2) | 83 | 48 | 25 | (10) | 12 |
| Genesee 2 forced outage | - | - | - | (5) | (12) | - | - | - |
| Provision for contingency | - | - | - | - | (6) | 6 | - | - |
| Impairment losses (reversal) | - | - | - | 41 | 6 | (2) | - | 10 |
| Reduction in applicable jurisdictional tax rates | - | - | - | 10 | - | - | (10) | - |
| Provision for Line Loss Rule Proceeding | - | - | - | - | - | - | (1) | 1 |
| Other | 12 | 5 | (2) | 4 | - | - | - | - |
| **Normalized earnings attributable to common shareholders** | **146** | **88** | **108** | **55** | **63** | **35** | **68** | **13** |
| Weighted average number of common shares outstanding (millions) | 116.7 | 116.4 | 116.2 | 116.0 | 115.5 | 109.7 | 106.8 | 105.7 |
| **Normalized earnings per share ($)** | **1.25** | **0.76** | **0.93** | **0.47** | **0.55** | **0.32** | **0.64** | **0.12** |

1 Includes impacts of the interest rate non-hedge held within a joint venture and recorded within income from joint venture on the Company's condensed interim consolidated statements of income.

## Forward-looking Information

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

Material forward-looking information in this press release includes disclosures regarding (i) status of, and updates to, the Company's 2022 AFFO and adjusted EBITDA guidance, (ii) expectations pertaining to the financial impacts of the acquisition and integration of Midland Cogen (see Significant Events), including the impacts to AFFO, AFFO per share and adjusted EBITDA, positioning for potential re-contracting following contract expiries in 2030 and 2035, and future site development opportunities, (iii) the timing of the investment decision for the Company's potential CCS project, (iv) forecasted depreciation for the remainder of 2022 and (v) expectations pertaining to the use of proceeds from the offering of Green Hybrid Subordinated Notes and future Green Financings pursuant to the Company's Green Financing Framework (see Significant Events).

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

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of 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 are: (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) generation facility availability, wind capacity factor and performance including maintenance expenditures, (iv) ability to fund current and future capital and working capital needs, (v) acquisitions and developments including timing and costs of regulatory approvals and construction, (vi) changes in the availability of fuel, (vii) ability to realize the anticipated benefits of acquisitions, (viii) limitations inherent in the Company's review of acquired assets, (ix) changes in general economic and competitive conditions and (x) changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs. See Risks and Risk Management in both the Company's Management's Discussion and Analysis for the nine months ended September 30, 2022, prepared as of October 28, 2022 and the Company's 2021 Integrated Annual Report, prepared as of February 23, 2022, for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the specified approval date. 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.

## About Capital Power

Capital Power (TSX: CPX) is a growth-oriented North American wholesale power producer with a strategic focus on sustainable energy headquartered in Edmonton, Alberta. We build, own, and operate high-quality, utility-scale generation facilities that include renewables and thermal. We have also made significant investments in carbon capture and utilization to reduce carbon impacts and are committed to be off coal in 2023. Capital Power owns approximately 7,400 MW of power generation capacity at 28 facilities across North America. Projects in advanced development include approximately 385 MW of owned renewable generation capacity in North Carolina and Alberta and 512 MW of incremental natural gas combined cycle capacity, from the repowering of Genesee 1 and 2 in Alberta.

## For more information, please contact:

**Media Relations**:
Katherine Perron
(780) 392-5335
kperron@capitalpower.com

**Investor Relations:**
Randy Mah
(780) 392-5305 or (866) 896-4636 (toll-free)
investor@capitalpower.com

# CAPITAL POWER CORPORATION

## Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A), prepared as of October 28, 2022, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the nine months ended September 30, 2022, the audited consolidated financial statements and Company Overview, Our Strategy and Business Report sections of the Integrated Annual Report of Capital Power Corporation for the year ended December 31, 2021 (the 2021 Integrated Annual Report), the Annual Information Form of Capital Power Corporation dated February 24, 2022, and the cautionary statements regarding forward-looking information which begin on page 9.

In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation together with its subsidiaries.

In this MD&A, financial information for the nine months ended September 30, 2022 and September 30, 2021 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of October 28, 2022.

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## FORWARD-LOOKING INFORMATION

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

Material forward-looking information in this MD&A includes expectations regarding:

- our 2022 performance targets and current period updates to our expectations, including for facility availability, sustaining capital expenditures, adjusted funds from operations (AFFO) and adjusted EBITDA;
- our company-wide targets specific to climate-related performance, including reduction of emissions and emissions intensity, repowering of Genesee 1 and Genesee 2 with the addition of battery storage and conversion of Genesee 3, completion of the Genesee Carbon Conversion Centre, commercial application of carbon conversion technologies and plans to be off coal in 2023;
- future revenues, expenses, earnings, adjusted EBITDA and AFFO;
- the future pricing of electricity and market fundamentals in existing and target markets;
- future dividend growth;
- the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions;
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings;
- expectations pertaining to the use of proceeds from the offering of Green Hybrid Subordinated Notes and future Green Financings pursuant to the Company's Green Financing Framework (see Significant Events);
- expectations pertaining to the integration and the financial impacts of the acquisition of Midland Cogeneration Venture Limited Partnership (Midland Cogen) (see Significant Events), including the impacts to AFFO, AFFO per share and adjusted EBITDA, positioning for potential re-contracting following contract expiries in 2030 and 2035, and future site development opportunities;
- the timing of, funding of and costs of existing, planned and potential development projects and acquisitions (including phase 2 of Halkirk Wind, the repowering of Genesee 1 and 2 (including being hydrogen ready and battery storage), Bear Branch Solar, Hornet Solar, Hunter's Cove Solar and Enchant Solar;
- facility availability and planned outages;
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects, commercial initiatives);
- forecasted impacts from the optimization of the Company's Alberta offset credits in 2022 and future years;
- market and regulation designs and the impact thereof on the Company's core markets; and
- the impacts of climate change and the Russia-Ukraine conflict.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, 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:

- electricity and other energy prices and carbon prices;
- performance;
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects;
- status of and impact of policy, legislation and regulations;
- effective tax rates;
- the development and performance of technology;
- foreign exchange rates;
- matters relating to the LLR Proceeding, including the timing and recovery from appropriate parties; and
- other matters discussed under the Performance Overview, Outlook and Risks and Risk Management sections.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of 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 are:

- changes in electricity, natural gas and carbon prices in markets in which the Company operates and the use of derivatives;
- regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation;
- disruptions, or price volatility within the Company's supply chains;
- generation facility availability, wind capacity factor and performance including maintenance expenditures;

- ability to fund current and future capital and working capital needs;
- acquisitions and developments including timing and costs of regulatory approvals and construction;
- changes in the availability of fuel;
- ability to realize the anticipated benefits of acquisitions;
- limitations inherent in the Company's review of acquired assets;
- changes in general economic and competitive conditions, including inflation;
- changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs; and
- risks and uncertainties discussed under the Risks and Risk Management section.

See Risks and Risk Management in the Company's 2021 Integrated Annual Report and Risks and Risk Management, for further discussion of these and other risks.

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.

## OVERVIEW OF BUSINESS AND CORPORATE STRUCTURE

Capital Power is a growth-oriented North American wholesale power producer with a strategic focus on sustainable energy headquartered in Edmonton, Alberta. We build, own, and operate high-quality, utility-scale generation facilities that include renewables and thermal. We have also made significant investments in carbon capture and utilization to reduce carbon impacts and are committed to be off coal in 2023. Capital Power owns approximately 7,400 megawatts (MW) of power generation capacity at 28 facilities across North America. Projects in advanced development include approximately 385 MW of owned renewable generation capacity in North Carolina and Alberta and 512 MW of incremental natural gas combined cycle capacity from the repowering of Genesee 1 and 2 in Alberta.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), Capital Power L.P. Holdings Inc., and Capital Power (US Holdings) Inc., all wholly owned subsidiaries of the Company.

## CORPORATE STRATEGY

The Company's corporate strategy and pathway towards net carbon neutral remains unchanged from that disclosed in its 2021 Integrated Annual Report.

## PERFORMANCE OVERVIEW

The Company measures our operational and financial performance in relation to our corporate strategy and progress toward our sustainability objectives through financial and non-financial targets that are approved by the Board of Directors of Capital Power. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include adjusted funds from operations and safety. The group-specific measures include facility operating margin and other operations measures, committed capital, construction and maintenance capital on budget and on schedule, and facility site safety.

### Operational excellence

#### Performance measure

Facility availability average

94%

Actual results[2]
2022 target of 93% or greater

Sustaining capital expenditures [1] (in millions)

$75

Actual results[2]
Updated guidance[3] of $130 to $140
2022 target of $105 to $115

1 Includes sustaining capital expenditures net of joint venture contributions of $4 million.
2 For the nine months ended September 30, 2022.
3 Based on the Company's year-to-date sustaining capital expenditures incurred, expectations of higher LTSA costs from increased generation, increased spend on shutdown work for the remainder of the year and sustaining capital expenditures for the Midland Cogen facility (see Significant Events) for the periods subsequent to the close of the transaction on September 23, 2022, the Company provided updated guidance for 2022.

The Company's facility availability averaged 94% which reflected planned outages at Arlington Valley, Genesee, Goreway, Joffre and Clover Bar Energy Centre. Unplanned outages also occurred at Genesee, Decatur, Arlington Valley and Clover Bar Energy Centre.

Sustaining capital expenditures for the nine months ended September 30, 2022 were lower than target for the year to date primarily due to various planned sustaining capital projects for which spending will occur later in the year. Full year sustaining capital expenditures are expected to be above the target range, primarily driven by expectations of higher LTSA costs from increased generation, increased spend on shutdown work and sustaining capital expenditures for the Midland Cogen facility (see Significant Events) for the remainder of the year.

### Disciplined growth

| Performance measure | 2022 target | Status at September 30, 2022 |
|---|---|---|
| Repowering of Genesee 1 and 2 | Continued progress with anticipated in-service date in late 2023 for the repowered Genesee Unit 1 and 2024 for Genesee Unit 2. | Construction is underway and the anticipated in-service date for Unit 1 has been revised to 2024 while Unit 2 remains consistent with target. The Company remains committed to be off coal in 2023. |
| Renewable projects: | Target completion dates on time and on budget for 2022 projects and progress on the development of 2024 projects to be on track with budget and completion dates: | Enchant Solar is expected to exceed the current budget, but remains on track with its targeted in-service date. The Company continues to develop its other renewable projects. |
| Strathmore Solar (Alberta) | Early 2022 | Completed on schedule (see Significant Events). |
| Enchant Solar (Alberta) | Fourth quarter of 2022 | |
| Bear Branch Solar (North Carolina) | Fourth quarter of 2024 | |
| Hornet Solar (North Carolina) | Fourth quarter of 2024 | |
| Hunter's Cove Solar (North Carolina) | Fourth quarter of 2024 | |
| Phase 2 of Halkirk Wind (Alberta) | Fourth quarter of 2024 | |
| Other growth | $500 million of committed capital | The Company exceeded its target for committed capital with its acquisition of Midland Cogen (see Significant Events). The Company continues to seek committed growth capital opportunities in the remainder of 2022. |

### Financial stability and strength

Adjusted funds from operations [1] (in millions)

$708

Actual results[2]
Updated guidance[3] of $770 to $810
2022 target of $580 to $630

Adjusted EBITDA [1] (in millions)

$1,050

Actual results[2]
Updated guidance[3] of $1,300 to $1,340
2022 target of $1,110 to $1,160

[1] Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures and Ratios.
[2] For the nine months ended September 30, 2022.
[3] Based on the Company's year-to-date results, expectations for the remainder of the year and the expected results from the acquisition of Midland Cogen facility (see Significant Events) for the periods subsequent to the close of the transaction on September 23, 2022, the Company provided updated guidance for 2022 (see Outlook).

## OUTLOOK

The following discussion should be read in conjunction with the forward-looking information section of this MD&A which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors.

At our Investor Day held in December 2021, the Company provided financial guidance for 2022 AFFO in the range of $580 million to $630 million and 2022 adjusted EBITDA in the range of $1,110 million to $1,160 million (see Non-GAAP Financial Measures and Ratios). During the second quarter of 2022, the Company provided updated guidance for its 2022 AFFO and adjusted EBITDA based on the actual year-to-date results for 2022, the Company's forecast for the remainder of the year, and the addition of the Midland Cogen facility (see Significant Events). Given the strength of the Company's performance in the third quarter of 2022, the projected range for 2022 AFFO and adjusted EBITDA has been further increased to $770 million to $810 million and $1,300 million to $1,340 million, respectively. The increased guidance ranges are driven most notably by the impact of higher Alberta power prices and generation along with strong performance across the facilities in the three months ended September 30, 2022 and expectations for the remainder of 2022 considering the Company's existing Alberta portfolio position for the balance of the year combined with strong forward pricing for our remaining Alberta generation. Partially offsetting the expectations for the remainder of 2022 is a change in the Company's strategy to optimize our Alberta offset credits inventory. As a result of higher generation from our baseload facilities in the current year, the revised anticipated in-service date of the repowering units and expected increase in Alberta's carbon compliance pricing by $15/tonne in 2023, the Company will be utilizing lower cost credits in 2023. The forecasted impact is an additional expense of approximately $50 million in 2022, while a decrease in carbon compliance expenses is expected in future years. Based on current forward Alberta pool pricing, 2023 adjusted EBITDA is forecasted to be generally in line with 2022.

During the first half of 2022, significant progress has been made on carbon capture, utilization and storage (CCUS). The Company completed a preliminary front-end engineering and design (FEED) study that updated various technical and cost parameters associated with the carbon capture facilities and FEED study activities are proceeding (see Significant Events). With respect to the CCUS policy framework, the Enbridge Open Access Wabamun Carbon Hub, which would provide transportation and sequestration services for the Genesee carbon capture and sequestration (CCS) Project among other projects, was awarded the right to pursue development of a carbon hub as part of the Government of Alberta's CCUS Hub process. As part of Budget 2022 tabled on April 7, 2022, the Government of Canada proposed a refundable investment tax credit (ITC) for investment in CCUS projects (see Regulatory Matters). Separately, as part of the 2030 Emissions Reduction Plan released on March 29, 2022, the Federal Government advised of its intention to explore measures that could provide greater certainty regarding carbon pricing in order to de-risk private sector low-carbon investments. These measures will help support the Company's proposed Genesee CCS Project and other carbon capture and conversion related initiatives, though the specific implications of these initiatives are being assessed.

Priorities for the Company for the remainder of 2022 include progressing our sustainability targets through:

- Continued progression on the repowering of Genesee 1 and 2 and conversion of Genesee 3,
- Further advancement of CCUS and carbon conversion technologies at the Genesee facility,
- Ongoing development of renewable projects, and
- Strategic acquisitions of renewable and natural gas assets.

Given the Company's acquisition of Midland Cogen (see Significant Events), finalizing the integration of Midland Cogen will be a priority during the remainder of 2022.

In 2022, Capital Power's availability target of 93% or greater reflects major scheduled maintenance outages for Genesee 1 and 3, Clover Bar Energy Centre, Goreway and Midland Cogen. Scheduled outages for 2021 covered Genesee 2, Decatur Energy and Shepard.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2023, 2024 and 2025 (all at September 30, 2022) were:

| Alberta commercial portfolio positions and power prices | Full year 2023 | Full year 2024 | Full year 2025 |
|---|---|---|---|
| Percentage of baseload generation sold forward [1] | 72% | 55% | 36% |
| Contracted price [2] | Low-$70 | Low-$60 | Low-$60 |
| Forward Alberta pool prices | $114 | $82 | $76 |
| Percentage of natural gas requirements purchased forward [3] | over 80% | over 70% | over 50% |
| Contracted Alberta natural gas price per GJ [2,4] | $1.50-$2.00 | $1.50-$2.00 | $2.50-$3.00 |
| Forward Alberta natural gas prices per GJ | $4.68 | $4.27 | $4.44 |

[1] Based on the Alberta baseload facilities plus a portion of Joffre and the uncontracted portion of Shepard.

[2] Forecasted average contracted prices may differ significantly from future average realized prices as future realized prices are driven by a combination of previously contracted prices and settled prices.

[3] Based on forecasted natural gas requirements from the Company's most recent forecast. Actual fuel requirements for Alberta facilities may differ significantly as a result of dispatch decisions.

[4] The Company presents average contracted Alberta natural gas prices based on $0.50 per GJ bands.

The 2022 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. They do not include the effects of potential future acquisitions or development activities, or potential market and operational impacts relating to unplanned facility outages including outages at facilities of other market participants, and the related impacts on market power prices.

At our Investor Day held in December 2021, the Company confirmed 5% annual dividend growth guidance for 2022 and announced the extension of our 5% annual dividend growth guidance to 2025. In July 2022, on the strength of anticipated contracted cash flows from the Midland Cogen acquisition (see Significant Events), the Company announced an increase of annual dividend growth guidance to 6% through 2025 from the previous 5%. Each annual increase is premised on the assumptions listed under Forward-Looking Information and subject to approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding. It is expected that, outside of new growth opportunities beyond currently announced projects, no additional common share equity will be required in 2022 to fund our current growth projects.

## NON-GAAP FINANCIAL MEASURES AND RATIOS

The Company uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits (adjusted EBITDA), (ii) AFFO, and (iii) normalized earnings attributable to common shareholders as financial performance measures.

The Company also uses AFFO per share and normalized earnings per share as performance measures. These measures are non-GAAP ratios determined by applying AFFO and normalized earnings attributable to common shareholders, respectively, to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

## Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations such as impairments, foreign exchange gains or losses, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits are excluded from the adjusted EBITDA measure.

A reconciliation of adjusted EBITDA to net income (loss) is as follows:

| (unaudited, $ millions) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| Revenues and other income | 786 | 713 | 501 | 672 | 377 | 387 | 554 | 516 |
| Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense | (543) | (429) | (178) | (506) | (162) | (176) | (264) | (321) |
| Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel | 136 | 28 | 18 | 123 | 66 | 24 | 7 | 19 |
| Adjusted EBITDA from joint ventures [1] | 4 | 7 | 7 | 5 | 5 | 6 | 6 | 6 |
| **Adjusted EBITDA** | **383** | **319** | **348** | **294** | **286** | **241** | **303** | **220** |
| Depreciation and amortization | (133) | (139) | (142) | (137) | (133) | (132) | (137) | (122) |
| Unrealized changes in fair value of commodity derivatives and emission credits | (136) | (28) | (18) | (123) | (66) | (24) | (7) | (19) |
| Impairment (losses) reversals | - | - | - | (52) | (8) | 2 | - | (13) |
| (Losses) gains on disposals and other transactions | (3) | (1) | - | 6 | 31 | (3) | 2 | - |
| Foreign exchange (loss) gain | (12) | (7) | 1 | (1) | (7) | (2) | 1 | 5 |
| Net finance expense | (40) | (35) | (37) | (44) | (43) | (46) | (41) | (57) |
| Finance expense and depreciation expense from joint ventures [1] | (4) | (1) | - | (4) | (4) | (5) | - | (4) |
| Income tax expense | (24) | (31) | (33) | (8) | (18) | (14) | (20) | (9) |
| **Net income (loss)** | **31** | **77** | **119** | **(69)** | **38** | **17** | **101** | **1** |
| | | | | | | | | |
| **Net income (loss) attributable to:** | | | | | | | | |
| Non-controlling interests | (3) | (3) | (3) | (4) | (2) | (3) | (2) | (2) |
| Shareholders of the Company | 34 | 80 | 122 | (65) | 40 | 20 | 103 | 3 |
| **Net income (loss)** | **31** | **77** | **119** | **(69)** | **38** | **17** | **101** | **1** |

[1] Total income from joint ventures as per the Company's consolidated statements of income.

## Adjusted funds from operations and adjusted funds from operations per share

AFFO and AFFO per share are measures of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, the repayment of debt and the payment of common share dividends.

AFFO represents net cash flows from operating activities adjusted to:

- remove timing impacts of cash receipts and payments that may impact period-to-period comparability which include deductions for net finance expense and current income tax expense, the removal of deductions for interest paid and income taxes paid and removing changes in operating working capital,
- include the Company's share of the AFFO of its joint venture interests and exclude distributions received from the Company's joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from off-coal compensation that will be received annually,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only the Company's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends,
- exclude the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty, and
- include net expected cash outflows for the Company's share of Line Loss Rule (LLR) Proceeding invoices in the period each tranche is paid by the Company.

A reconciliation of net cash flows from operating activities to adjusted funds from operations is as follows:

| (unaudited, $ millions) | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | **2022** | **2021** | **2022** | **2021** |
| **Net cash flows from operating activities per condensed interim consolidated statements of cash flows** | **370** | **347** | **893** | **682** |
| Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows: | | | | |
| Interest paid | 22 | 37 | 76 | 98 |
| Realized gains on settlement of hedged interest rate derivatives | (27) | - | (27) | (12) |
| Change in fair value of derivatives reflected as cash settlement | 15 | 6 | 60 | 17 |
| Distributions received from joint ventures | (4) | (3) | (6) | (8) |
| Miscellaneous financing charges paid [1] | 1 | 1 | 5 | 4 |
| Income taxes paid (recovered) | 7 | (18) | 24 | (13) |
| Change in non-cash operating working capital | (46) | (120) | (151) | (105) |
| | (32) | (97) | (19) | (19) |
| Net finance expense [2] | (20) | (29) | (80) | (93) |
| Current income tax expense [3] | (15) | (3) | (39) | (19) |
| Sustaining capital expenditures [4] | (20) | (52) | (75) | (99) |
| Preferred share dividends paid | (9) | (12) | (29) | (38) |
| Cash received for off-coal compensation | 50 | 50 | 50 | 50 |
| Remove tax equity interests' respective shares of adjusted funds from operations | (1) | (1) | (9) | (7) |
| Adjusted funds from operations from joint ventures | 5 | 3 | 16 | 12 |
| Line Loss Rule Proceeding [5] | - | - | - | (13) |
| **Adjusted funds from operations** | **328** | 206 | **708** | 456 |
| Weighted average number of common shares outstanding (millions) | **116.7** | **115.5** | **116.4** | **110.7** |
| **Adjusted funds from operations per share ($)** | **2.81** | **1.78** | **6.08** | **4.12** |

[1] Included in other cash items on the condensed interim consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

[2] Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges and non-cash implicit interest on tax equity investment structures.

[3] For the three and nine months ended September 30, 2021, excludes current income tax expenses of $6 million and $14 million, respectively, related to the Genesee 3 and Keephills 3 swap transaction as these amounts are considered investing activities.

4 Includes sustaining capital expenditures net of partner contributions of $2 million and $4 million for the three and nine months ended September 30, 2022, respectively, compared with $1 million and $8 million for the three and nine months ended September 30, 2021, respectively.

5 Consistent with the Company's definition of AFFO described above pertaining to the LLR Proceeding, AFFO for the three months and nine months ended September 30, 2021 is impacted only by the Company's net obligations related to the 2006-2009 and 2010–2013 invoice tranches (see Contingent Liabilities, Other Legal Matters and Provisions).

### Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings attributable to common shareholders and normalized earnings per share are based on net income (loss) attributable to shareholders of the Company according to GAAP and adjusted for items that are not reflective of performance in the period such as unrealized fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange gain or loss on the revaluation of U.S. dollar denominated debt. The adjustments, shown net of tax, consist of unrealized fair value changes on financial instruments that are not necessarily indicative of future actual realized gains or losses, non-recurring gains or losses, or gains or losses reflecting corporate structure decisions.

| (unaudited, $ millions except per share amounts and number of common shares) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| **Basic earnings (loss) per share ($)** | **0.21** | **0.59** | **0.96** | **(0.67)** | **0.23** | **0.05** | **0.83** | **(0.09)** |
| **Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)** | **34** | **80** | **122** | **(65)** | **40** | **20** | **103** | **3** |
| Preferred share dividends including Part VI.1 tax | (10) | (11) | (10) | (13) | (13) | (14) | (14) | (13) |
| Earnings (loss) attributable to common shareholders | 24 | 69 | 112 | (78) | 27 | 6 | 89 | (10) |
| Unrealized changes in fair value of derivatives [1] | 110 | 14 | (2) | 83 | 48 | 25 | (10) | 12 |
| Genesee 2 forced outage | - | - | - | (5) | (12) | - | - | - |
| Provision for contingency | - | - | - | - | (6) | 6 | - | - |
| Impairment losses (reversal) | - | - | - | 41 | 6 | (2) | - | 10 |
| Reduction in applicable jurisdictional tax rates | - | - | - | 10 | - | - | (10) | - |
| Provision for Line Loss Rule Proceeding | - | - | - | - | - | - | (1) | 1 |
| Other | 12 | 5 | (2) | 4 | - | - | - | - |
| **Normalized earnings attributable to common shareholders** | **146** | **88** | **108** | **55** | **63** | **35** | **68** | **13** |
| Weighted average number of common shares outstanding (millions) | 116.7 | 116.4 | 116.2 | 116.0 | 115.5 | 109.7 | 106.8 | 105.7 |
| **Normalized earnings per share ($)** | **1.25** | **0.76** | **0.93** | **0.47** | **0.55** | **0.32** | **0.64** | **0.12** |

1 Includes impacts of the interest rate non-hedges held within joint ventures and recorded within income from joint ventures on the Company's condensed interim consolidated statements of income.

## FINANCIAL HIGHLIGHTS

| (unaudited, $ millions, except per share amounts) | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | 2022 | 2021 | 2022 | 2021 |
| Revenues and other income | 786 | 377 | 2,000 | 1,318 |
| Adjusted EBITDA [1] | 383 | 286 | 1,050 | 830 |
| Net income | 31 | 38 | 227 | 156 |
| Net income attributable to shareholders of the Company | 34 | 40 | 236 | 163 |
| Normalized earnings attributable to common shareholders [1] | 146 | 63 | 342 | 166 |
| Basic earnings per share ($) | 0.21 | 0.23 | 1.76 | 1.10 |
| Diluted earnings per share ($) [2] | 0.20 | 0.23 | 1.75 | 1.09 |
| Normalized earnings per share ($) [1] | 1.25 | 0.55 | 2.94 | 1.50 |
| Net cash flows from operating activities | 370 | 347 | 893 | 682 |
| Adjusted funds from operations [1] | 328 | 206 | 708 | 456 |
| Adjusted funds from operations per share ($) [1] | 2.81 | 1.78 | 6.08 | 4.12 |
| Purchase of property, plant and equipment and other assets, net | 224 | 176 | 503 | 424 |
| Dividends per common share, declared ($) | 0.5800 | 0.5475 | 1.6750 | 1.5725 |
| Dividends per Series 1 preferred share, declared ($) | 0.1638 | 0.1638 | 0.4914 | 0.4914 |
| Dividends per Series 3 preferred share, declared ($) | 0.3408 | 0.3408 | 1.0224 | 1.0224 |
| Dividends per Series 5 preferred share, declared ($) | 0.3274 | 0.3274 | 0.9821 | 0.9821 |
| Dividends per Series 7 preferred share, declared ($) [3] | N/A | 0.3750 | N/A | 1.1250 |
| Dividends per Series 9 preferred share, declared ($) [4] | 0.3594 | 0.3594 | 1.0781 | 1.0781 |
| Dividends per Series 11 preferred share, declared ($) | 0.3594 | 0.3594 | 1.0781 | 1.0781 |

| | As at | |
|---|---|---|
| | September 30, 2022 | December 31, 2021 |
| Loans and borrowings including current portion | 3,424 | 3,360 |
| Total assets | 9,756 | 9,073 |

1 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share, AFFO and AFFO per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.

2 Diluted earnings per share was calculated after giving effect to outstanding share purchase options.

3 On December 31, 2021, the Company redeemed all of its 8 million issued and outstanding 6.00% cumulative rate reset preference shares, Series 7.

4 On September 30, 2022, the Company redeemed all of its 6 million issued and outstanding 5.75% cumulative rate reset preference shares, Series 9 (see Significant Events).

See Consolidated Net Income and Results of Operations for discussion of the key drivers of the changes in revenues and other income, adjusted EBITDA, net income and net income attributable to shareholders of the Company.

The changes in basic and diluted earnings per share were driven by the same factors as net income which are discussed in Consolidated Net Income and Results of Operations and the changes from period to period in the weighted average number of common shares outstanding. The changes in normalized earnings per share and normalized earnings attributable to common shareholders were affected by the same drivers as basic earnings per share, but also the adjustments between income (loss) per share and normalized earnings per share described under Non-GAAP Financial Measures and Ratios.

See Liquidity and Capital Resources for discussion of the key drivers of the changes in net cash flows from operating activities. AFFO for the three months ended September 30, 2022 was higher than the corresponding period in 2021 primarily due to:

- higher adjusted EBITDA results mainly attributable to the higher generation and realized power pricing on our Alberta commercial facilities, higher dispatch at Goreway, and higher generation and capacity revenues at Decatur,
- lower net finance expense due to higher capitalized interest resulting from continued progression on the Genesee repowering project and realized gains from the settlement of the Company's non-hedge interest rate swap contributed to the lower net finance expense during the quarter. This was partially offset by increased interest from loans and borrowings outstanding primarily due to the private placement of senior notes issued in

the fourth quarter of 2021, and

- lower preferred share dividends paid due to the redemption of Series 7 preferred shares by the Company in the fourth quarter of 2021.

On a year-to-date basis, higher AFFO for the nine months ended September 30, 2022 further reflects:

- more frequent dispatch and strong availability from our U.S. contracted thermal facilities, and
- the impacts of the Company’s obligation related to the second and third tranches of LLR Proceeding in the first half of 2021 compared to no LLR proceeding impacts in the current period.

Partially offsetting the above was higher current income tax expense for the three and nine months ended September 30, 2022 driven by prior year's income before tax. The current income tax expense related to income before tax for 2022 will be incurred in 2023. Lower sustaining capital expenditures in both periods were primarily due to costs incurred related to the Genesee 2 unplanned outage in 2021.

The increase in purchases of property, plant and equipment and other assets for the nine months ended September 30, 2022 is discussed in Liquidity and Capital Resources.

## SIGNIFICANT EVENTS

### Preferred shares, Series 9, redemption

On September 30, 2022, the Company redeemed all of its 6 million issued and outstanding 5.75% Cumulative Minimum Rate Reset Preference Shares, Series 9 (Series 9 Shares) at a price of $25.00 per share for gross payments of $150 million. On September 30, 2022, the Company also paid the final declared quarterly dividend of $0.3594 per Series 9 Share.

### Acquisition of Midland Cogeneration Venture

On September 23, 2022, Capital Power and Manulife Investment Management, on behalf of the Manulife Infrastructure Fund II and its affiliates completed its previously announced acquisition of 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.

Capital Power’s investment for its 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 its share of the transaction using cash on hand and its existing credit facilities. The Company expects to finalize the working capital adjustment in the fourth quarter of 2022. Due to the proximity of the acquisition’s closing date to September 30, 2022, the equity income from MCV Partners LLC was not material in the quarter. Substantially all of the underlying assets and liabilities of Midland Cogen relate to the cogeneration facility and the project level debt. Capital Power is responsible for operations and maintenance and asset management for which it will receive an annual management fee.

Located in Michigan, Midland Cogen, the largest gas-fired cogeneration facility in North America, is a critical asset to support grid reliability during the transition to renewables and is well-positioned, given anticipated market conditions, for recontracting beyond 2030.

The acquisition supports Capital Power’s strategy of acquiring mid-life contracted natural gas assets that are strategically positioned within their power markets. Acquisition highlights include:

- Capital Power’s share of expected average adjusted EBITDA of US$59 million per year (ranging from US$85 million in 2023 and declining to US$45 million in 2027).
- based on the actual financing, the 5-year average accretion for Capital Power’s AFFO is expected to be US$0.30 per share, reflecting a 7% increase, or an average AFFO of US$35 million per year during the years 2023-2027.
- power purchase agreement with Consumers Energy (rated Baa1/A-/A-) for 1,240 MW of capacity to 2030
- steam and electricity purchase agreement with Corteva Agriscience (rated NA/A-/A) and Dow Silicones (rated Baa2/BBB/BBB+) to 2035.
- approximately 15% (243 MW) of uncontracted capacity is available to sell into the MISO Zone 7 market.
- located on 1,200 acres leased from Consumers Energy. Current layout and additional space allow for additional turbines, battery installation or a hybrid opportunity.

### $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 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 Series 1 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 indenture governing the Subordinated Notes.

This is the first ever Green hybrid subordinated debt security in Canada and represents the Company's first green offering under Capital Power's short form base prospectus dated June 10, 2022, as supplemented by a prospectus supplement dated August 18, 2022. 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 the Company's Green Financing Framework (see Significant Events).

### Green Financing Framework

On August 15, 2022, the Company released its inaugural Green Financing Framework (Framework) under which the Company will issue green bonds and green loans (Green Financing). The 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 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 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 Framework, and are aligned with the United Nations Sustainable Development Goals: affordable and clean energy; industry, innovation and infrastructure; and climate action.

Until the Green Financing issued under this Framework is fully allocated, Capital Power will report publicly on the use of the proceeds within one year of issuance and annually thereafter. Both the Allocation and Impact Reports will be posted on the Company's website. An external verification of the Allocation Report will be provided by an independent external auditor on an annual basis until the complete allocation of proceeds.

Sustainalytics reviewed the Framework and provided a second-party opinion confirming that the Framework is credible and impactful and aligns with the Green Bond Principles 2021 and Green Loan Principles 2021. BMO Capital Markets advised Capital Power on the development of the Framework as lead structuring agent.

### Dividend increase

On July 29, 2022, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $2.19 per common share to $2.32 per common share. This increased common share dividend commenced with the third quarter 2022 quarterly dividend payment on October 31, 2022, to shareholders of record at the close of business on September 30, 2022.

### Advancement of carbon capture project at Genesee

On June 27, 2022, the Company announced it had partnered with Mitsubishi Heavy Industries Group and Kiewit Energy Group on a front-end engineering and design (FEED) study for the Genesee CCS Project advancing the commercial application of CCS technology at its Genesee Generating Station in Alberta.

### Appointment to the Board of Directors

Effective June 1, 2022, Gary Bosgoed was appointed to the Company's Board of Directors. With this appointment, Capital Power's Board of Directors consists of 10 directors, including 40% women and 30% with diversity beyond gender.

### Executed 4.5-year contract renewal for Island Generation

On May 16, 2022, the Company announced the execution of a 4.5-year Electricity Purchase Agreement (EPA) through October 2026 for its Island Generation facility with BC Hydro. The EPA is subject to regulatory approval by the British Columbia Utilities Commission. The terms of the 4.5-year EPA are consistent with the Company's expectations when it recorded a $52 million impairment in 2021.

### Executed 10-year contract for Whitla Wind

On March 18, 2022, the Company announced that it executed a 10-year renewable energy agreement with MEGlobal Canada ULC. The agreement commenced April 1, 2022, and covers the renewable energy for the balance of our Whitla Wind facility.

### Strathmore Solar begins commercial operations

On March 17, 2022, Strathmore Solar, a 41 MW facility in Strathmore Alberta, began commercial operations. The project was completed on-schedule at a total cost of $58 million compared to the original projected total cost of $53 million (see Liquidity and Capital Resources). The facility is fully contracted with 100% of the renewable energy and associated renewable energy credits sold to TELUS Communications under a 25-year power purchase agreement.

### Approval of normal course issuer bid

During the first quarter of 2022, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 8 million of its outstanding common shares during the one-year period from February 28, 2022, to February 27, 2023.

## CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and nine months ended September 30, 2022 compared with 2021 are presented below followed by further discussion of these items.

| (unaudited, $ millions) | **Three months** | | **Nine months** | |
|---|---|---|---|---|
| **Consolidated net income for the periods ended September 30, 2021** | | **38** | | **156** |
| Increase (decrease) in adjusted EBITDA: | | | | |
| Alberta commercial facilities and portfolio optimization | 102 | | 175 | |
| Western Canada contracted facilities | (3) | | 10 | |
| Ontario contracted facilities | 6 | | 21 | |
| U.S. contracted facilities | 7 | | 37 | |
| Corporate | (15) | 97 | (23) | 220 |
| Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits | | (70) | | (85) |
| Increase in depreciation and amortization expense | | - | | (12) |
| Decrease in gains on disposals and other transactions | | (34) | | (34) |
| Decrease in impairments, net of reversal | | 8 | | 6 |
| Increase in foreign exchange loss | | (5) | | (10) |
| Decrease in finance expense and depreciation expense from joint ventures | | - | | 4 |
| Decrease in net finance expense | | 3 | | 18 |
| (Decrease) increase in income before tax | | (1) | | 107 |
| Increase in income tax expense | | (6) | | (36) |
| **(Decrease) increase in net income** | | (7) | | **71** |
| **Consolidated net income for the periods ended September 30, 2022** | | **31** | | **227** |

## Results by facility category and other

| | Three months ended September 30 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2022 | 2021 | 2022 | 2021 | 2022 | 2021 | 2022 | 2021 |
| | **Electricity generation** (GWh) [1] | | **Facility availability** (%) [2] | | **Revenues and other income** (unaudited, $ millions) | | **Adjusted EBITDA** (unaudited, $ millions) [3] | |
| Total electricity generation, average facility availability and facility revenues | 6,993 | 6,103 | 96 | 91 | 1,095 | 539 | | |
| **Alberta commercial facilities** | | | | | | | | |
| Genesee 1 | 863 | 824 | 99 | 94 | 195 | 82 | | |
| Genesee 2 | 803 | 156 | 93 | 19 | 177 | 24 | | |
| Genesee 3 | 988 | 1,009 | 99 | 99 | 219 | 100 | | |
| Clover Bar Energy Centre 1, 2 and 3 | 218 | 235 | 93 | 97 | 75 | 32 | | |
| Joffre | 135 | 166 | 81 | 92 | 40 | 25 | | |
| Shepard | 824 | 739 | 98 | 100 | 106 | 52 | | |
| Halkirk Wind | 87 | 98 | 94 | 96 | 18 | 13 | | |
| Clover Bar Landfill Gas | 2 | - | 69 | 24 | - | - | | |
| Alberta commercial facilities | 3,920 | 3,227 | 95 | 83 | 830 | 328 | | |
| Portfolio optimization | N/A | N/A | N/A | N/A | (257) | (15) | | |
| | 3,920 | 3,227 | 95 | 83 | 573 | 313 | 234 | 132 |
| **Western Canada contracted facilities** | | | | | | | | |
| Island Generation | - | 424 | 100 | 96 | 4 | 9 | | |
| Quality Wind | 93 | 101 | 99 | 96 | 12 | 12 | | |
| EnPower | 2 | - | 92 | 100 | - | - | | |
| Whitla Wind | 238 | 156 | 92 | 95 | 11 | 7 | | |
| Strathmore Solar [4] | 26 | N/A | 100 | N/A | 2 | N/A | | |
| | 359 | 681 | 96 | 96 | 29 | 28 | 17 | 20 |
| **Ontario contracted facilities** | | | | | | | | |
| York Energy [5] | 8 | 6 | 96 | 87 | N/A | N/A | | |
| East Windsor | 6 | 4 | 93 | 100 | 8 | 8 | | |
| Goreway | 721 | 453 | 100 | 100 | 110 | 66 | | |
| Kingsbridge 1 | 14 | 13 | 96 | 99 | 1 | 1 | | |
| Port Dover and Nanticoke Wind | 50 | 47 | 90 | 90 | 7 | 7 | | |
| | 799 | 523 | 98 | 97 | 126 | 82 | 59 | 53 |
| **U.S. contracted facilities** | | | | | | | | |
| Decatur Energy, Alabama | 785 | 381 | 98 | 94 | 43 | 34 | | |
| Arlington Valley, Arizona | 685 | 876 | 97 | 100 | 39 | 36 | | |
| Beaufort Solar, North Carolina | 8 | 8 | 100 | 96 | 1 | 1 | | |
| Bloom Wind, Kansas | 126 | 132 | 95 | 90 | 8 | 7 | | |
| Macho Springs Wind, New Mexico | 17 | 15 | 97 | 97 | 2 | 1 | | |
| New Frontier Wind, North Dakota | 83 | 92 | 94 | 95 | 3 | 5 | | |
| Cardinal Point Wind, Illinois | 86 | 93 | 96 | 96 | 9 | 12 | | |
| Buckthorn Wind, Texas | 64 | 75 | 92 | 96 | 5 | 5 | | |
| Midland Cogen, Michigan [6] | 61 | N/A | 86 | N/A | N/A | N/A | | |
| | 1,915 | 1,672 | 96 | 96 | 110 | 101 | 92 | 85 |
| **Corporate** [7] | | | | | 33 | 32 | (19) | (4) |
| Unrealized changes in fair value of commodity derivatives and emission credits | | | | | (85) | (179) | | |
| **Consolidated revenues and other income and adjusted EBITDA** | | | | | **786** | **377** | **383** | **286** |

| | Nine months ended September 30 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2022 | 2021 | 2022 | 2021 | 2022 | 2021 | 2022 | 2021 |
| | **Electricity generation** (GWh) [1] | | **Facility availability** (%) [2] | | **Revenues and other income** (unaudited, $ millions) | | **Adjusted EBITDA** (unaudited, $ millions) [3] | |
| Total electricity generation, average facility availability and facility revenues | 20,524 | 16,708 | 94 | 90 | 2,399 | 1,620 | | |
| **Alberta commercial facilities** | | | | | | | | |
| Genesee 1 | 2,386 | 2,148 | 93 | 93 | 363 | 223 | | |
| Genesee 2 | 2,463 | 1,438 | 96 | 72 | 362 | 165 | | |
| Genesee 3 | 2,978 | 2,864 | 100 | 96 | 426 | 288 | | |
| Clover Bar Energy Centre 1, 2 and 3 | 402 | 325 | 90 | 97 | 107 | 54 | | |
| Joffre | 531 | 549 | 92 | 96 | 102 | 78 | | |
| Shepard | 2,424 | 1,921 | 99 | 83 | 219 | 143 | | |
| Halkirk Wind | 361 | 360 | 96 | 97 | 55 | 46 | | |
| Clover Bar Landfill Gas | 5 | - | 78 | 8 | 1 | - | | |
| Alberta commercial facilities | 11,550 | 9,605 | 96 | 89 | 1,635 | 997 | | |
| Portfolio optimization | N/A | N/A | N/A | N/A | (183) | (27) | | |
| | 11,550 | 9,605 | 96 | 89 | 1,452 | 970 | 608 | 433 |
| **Western Canada contracted facilities** | | | | | | | | |
| Island Generation | 7 | 566 | 100 | 95 | 17 | 27 | | |
| Quality Wind | 289 | 311 | 97 | 97 | 37 | 37 | | |
| EnPower | 14 | 18 | 97 | 94 | 1 | 1 | | |
| Whitla Wind | 1,023 | 569 | 96 | 97 | 50 | 25 | | |
| Strathmore Solar [4] | 55 | N/A | 100 | N/A | 4 | N/A | | |
| | 1,388 | 1,464 | 98 | 96 | 109 | 90 | 77 | 67 |
| **Ontario contracted facilities** | | | | | | | | |
| York Energy [5] | 22 | 15 | 99 | 96 | N/A | N/A | | |
| East Windsor | 12 | 8 | 89 | 99 | 26 | 23 | | |
| Goreway | 1,554 | 846 | 86 | 96 | 255 | 171 | | |
| Kingsbridge 1 | 72 | 63 | 98 | 99 | 6 | 5 | | |
| Port Dover and Nanticoke Wind | 217 | 194 | 96 | 96 | 32 | 29 | | |
| | 1,877 | 1,126 | 90 | 96 | 319 | 228 | 180 | 159 |
| **U.S. contracted facilities** | | | | | | | | |
| Roxboro, North Carolina [8] | N/A | 57 | N/A | 100 | N/A | 7 | | |
| Southport, North Carolina [8] | N/A | 60 | N/A | 100 | N/A | 11 | | |
| Decatur Energy, Alabama | 2,154 | 977 | 97 | 75 | 93 | 70 | | |
| Arlington Valley, Arizona | 1,820 | 1,882 | 91 | 92 | 127 | 95 | | |
| Beaufort Solar, North Carolina | 23 | 22 | 100 | 98 | 2 | 2 | | |
| Bloom Wind, Kansas | 514 | 474 | 94 | 94 | 25 | 25 | | |
| Macho Springs Wind, New Mexico | 99 | 94 | 97 | 98 | 11 | 10 | | |
| New Frontier Wind, North Dakota | 321 | 288 | 95 | 95 | 16 | 16 | | |
| Cardinal Point Wind, Illinois | 449 | 404 | 96 | 97 | 43 | 42 | | |
| Buckthorn Wind, Texas | 268 | 255 | 91 | 95 | 19 | 27 | | |
| Midland Cogen, Michigan [6] | 61 | N/A | 86 | N/A | N/A | N/A | | |
| | 5,709 | 4,513 | 95 | 86 | 336 | 305 | 212 | 175 |
| **Corporate** [7] | | | | | 98 | 94 | (27) | (4) |
| Unrealized changes in fair value of commodity derivatives and emission credits | | | | | (314) | (369) | | |
| **Consolidated revenues and other income and adjusted EBITDA** | | | | | **2,000** | **1,318** | **1,050** | **830** |

1 Gigawatt hours (GWh) of electricity generation reflects the Company's share of facility output.

2 Facility availability represents the percentage of time in the period that the facility was available to generate power regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

3 The financial results by facility category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.

4 Strathmore Solar was commissioned on March 17, 2022.

5 York Energy is accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint ventures on the Company's condensed interim consolidated statements of income. Capital Power's share of the facility's adjusted EBITDA is included in adjusted EBITDA above. The equivalent of Capital Power's share of the facility's revenue was $8 million and $27 million for three and nine months ended September 30, 2022, respectively, compared with $8 million and $23 million for the three and nine months ended September 30, 2021. The facility's revenues are not included in the above results.

6 Midland Cogen was acquired September 23, 2022 (see Significant Events) and is accounted for under the equity method. Due to the proximity of the acquisition's closing date to September 30, 2022, Capital Power's share of the facility's adjusted EBITDA and revenues were not material in the three and nine months ended September 30, 2022.

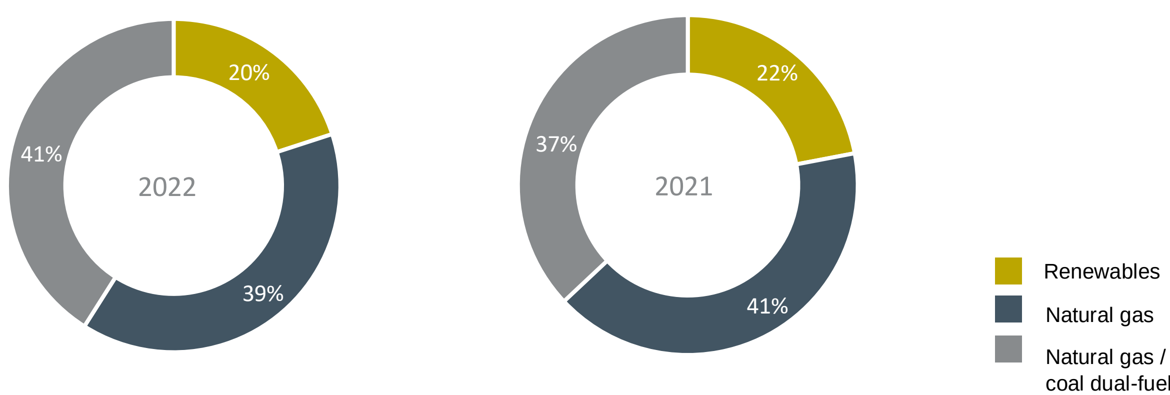
7 Corporate revenues were offset by interplant category eliminations.

8 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations. Decommissioning of the facilities commenced in the second quarter of 2021 and is ongoing.

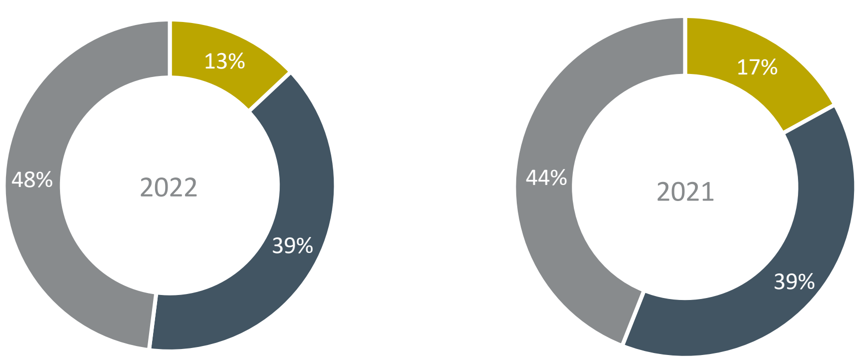
***Adjusted EBITDA and revenues and other income by fuel type for the nine months ended September 30***

Alberta commercial portfolio optimization amounts in adjusted EBITDA and revenues and other income are allocated to fuel source based on generation and off-coal compensation is reflected within natural gas / coal dual-fuel. The period-over-period increases in percentages from the Company's natural gas/coal dual-fuel facilities are largely driven by higher generation and realized Alberta power prices in 2022 as compared to 2021.This more than offset the period-over-period percentage increases from the growth of the Company's renewables facilities.

Adjusted EBITDA by fuel type




Revenues and other income by fuel type[1]




1 The allocation of revenues and other income by fuel type excludes the impacts of unrealized changes in fair value of commodity derivatives and emission credits.

***Energy prices and hedged positions***

| Alberta portfolio metric | Unit | Three months ended September 30 2022 | Three months ended September 30 2021 | Nine months ended September 30 2022 | Nine months ended September 30 2021 | Year ended December 31, 2021 |
|---|---|---|---|---|---|---|
| **Power** | | | | | | |
| Hedged position [1] | Percentage of baseload generation sold forward at beginning of period (%) | 95 | 69 | 76 | 33 | 29 |
| Spot power price average | $ per MWh | 221 | 100 | 145 | 100 | 102 |
| Realized power price [2] | $ per MWh | 101 | 75 | 90 | 76 | 78 |
| **Natural gas** | | | | | | |
| Hedged position[3] | Percentage of natural gas requirements purchased forward at beginning of period (%) | 100 | 91 | 100 | 81 | 78 |
| Spot natural gas price average (AECO) [4] | $ per GJ | 4.02 | 3.32 | 5.14 | 3.14 | 3.50 |

1 Hedged position is for the Alberta baseload plants as well as a portion of Joffre and the uncontracted portion of Shepard.

2 Realized power price is the average aggregate price realized through selling power generation into the spot market, the Company's commercial contracted sales and portfolio optimization activities. When long-term forward portfolio optimization hedges are transacted, they reflect the market's expectations for future period pricing. Ultimately, spot pricing may vary from expected forward pricing due to a number of factors resulting in realized power prices in a given period that can differ materially from spot pricing.

3 Based on forecasted natural gas requirements from the Company's most recent forecast. Actual fuel requirements for Alberta facilities may differ significantly as a result of dispatch decisions.

4 AECO refers to the historical virtual trading hub located in Alberta and known as the NOVA Inventory Transfer system operated by TC Energy. Realized natural gas price is the average aggregate price realized through purchasing of natural gas from the spot market, the Company's commercial contracted purchases and portfolio optimization activities. For the current and comparative periods, this results in realized natural gas prices that are significantly lower than spot natural gas prices.

***Alberta commercial facilities and portfolio optimization***

The Alberta power spot price averaged $221 per MWh and $145 per MWh for the three and nine months ended September 30, 2022, respectively, which were higher than the corresponding periods in 2021. This was primarily due to competitive bidding behaviors that resulted from increased demand driven by above average temperatures as well as various gas units and tie-line outages during the third quarter of 2022 leading to the pricing of natural gas units higher in the merit curve. In addition, higher natural gas prices year-over-year, increased carbon compliance pricing from $40 per tonne in 2021 to $50 per tonne in 2022, lower imports and overall increase in demand contributed to higher spot price in the current year.

For the three and nine months ended September 30, 2022, generation and availability were higher than the comparable periods in 2021. These increases were primarily driven by Alberta power market fundamentals, the Company's offer strategy and the generator failure at Genesee 2 in July 2021. A summary of the other larger outages for Alberta commercial facilities is below:

- a planned outage at Shepard in the second quarter of 2021 compared with minimal outage hours thus far in 2022;
- longer planned and unplanned outages across all quarters at Clover Bar Energy Center in 2022 compared with 2021;
- shorter unplanned outages and no planned outage in the first three quarters of 2022 compared with unplanned outages and a planned outage in the second quarter of 2021 at Genesee 3;
- a planned outage at Genesee 1 across the first two quarters of 2022 which was consistent in duration with the unplanned outages experienced across the first three quarters of 2021; and
- a longer planned outage at Joffre in the third quarter of 2022 compared with the planned outage in the third quarter of 2021 as well as longer unplanned outages in 2022 compared with 2021.

Revenues and other income for the three months ended September 30, 2022 were higher than the comparable periods in 2021 primarily due to the higher generation at Genesee, largely driven by Unit 2 generator failure in July 2021, and Shepard as well as higher captured prices for the portfolio in 2022 compared with 2021. Year-to-date results for 2022 further reflects higher revenues and other income driven by higher generation across the majority of the Company's Alberta commercial facilities compared to the same period of 2021.

Adjusted EBITDA for the three and nine months ended September 30, 2022 was higher than the comparable periods in 2021 primarily due to the aforementioned higher revenues and other income. These favourable variances were partially offset by higher coal and natural gas prices, as well as higher volumes burned in 2022 compared with 2021 given increased generation. In addition, the aforementioned higher generation and carbon compliance pricing have led to higher emissions costs in 2022 compared with 2021.

***Western Canada contracted facilities***

Generation was impacted primarily by the commencement of operations for phases 2 and 3 of Whitla Wind on December 1, 2021 and Strathmore Solar on March 17, 2022 and minimal dispatch at Island Generation in 2022 compared with 2021.

Revenues and other income, for the three and nine months ended September 30, 2022 was higher compared to the corresponding periods in 2021 primarily due to the renewable facilities that commenced operations between December 2021 and March 2022, partially offset by lower revenues at Island Generation during the period where the old EPA expired and the new EPA was being negotiated, as well as lower net revenues recognized as a result of classifying the new EPA as a finance lease (see Significant Events).

Adjusted EBITDA for the three months ended September 30, 2022, compared to the corresponding period in 2021 was lower primarily due to the aforementioned Island Generation revenue and other income variances, which more than offset the adjusted EBITDA contribution of phases 2 and 3 of Whitla Wind and Strathmore in the third quarter of 2022. Adjusted EBITDA for the nine months ended September 30, 2022, compared to the corresponding period in 2021 was higher primarily due to the renewable facilities that commenced operations within the last year, partially offset by the aforementioned lower revenue and other income at Island Generation.

Availability for the nine months ended September 30, 2022 was higher compared to the corresponding periods in 2021 primarily due to unplanned outages in the second and third quarters of 2021 at Island Generation compared with no outages thus far in 2022 coupled with strong availability at the aforementioned facilities that commenced operations within the last year.

***Ontario contracted facilities***

Generation, revenues and other income, and adjusted EBITDA for the three and nine months ended September 30, 2022 were higher compared to the corresponding periods in 2021 primarily due to higher dispatch at Goreway, largely driven by nuclear refurbishment and other outage activities which are limiting power supply in the Ontario market and warmer temperatures. In addition, higher wind resourcing experienced at Port Dover and Nanticoke Wind and higher market and ancillary services revenues at East Windsor contributed to higher revenues and other income in 2022 compared with 2021. Partially offsetting these impacts within adjusted EBITDA for the three and nine months ended September 30, 2022 were higher outage costs due to a longer planned outage in the second quarter of 2022 compared with the same period in 2021 at Goreway. Unplanned outages at East Windsor in 2022 compared with minimal outage hours in 2021 also contributed to the lower availability for the nine months ended September 30, 2022 compared with the same period in 2021, partially offset by a longer planned outage at York Energy in the third quarter of 2021 compared with the planned outage in the same period in 2022.

***U.S. contracted facilities***

Generation and availability for the three months ended September 30, 2022 were higher than the comparable period in 2021 primarily due to activities at Decatur Energy. Arlington Valley further contributed to the higher generation year-to-date in 2022 compared to the same period in 2021. Decatur Energy was dispatched for longer periods and did not have a planned outage in 2022 compared with a planned outage across both the first and second quarters of 2021 as well as shorter and fewer unplanned outages in the third quarter of 2022 compared with the same period in 2021. The acquisition of Midland Cogen (see Significant Events) also contributed to the higher generation in 2022. In addition, overall generation from the renewables facilities was higher in the first half of 2022 compared with the same period in 2021 and lower in the third quarter of 2022 compared with the same period in 2021 due to wind resource availability. Offsetting the increases to generation was the retirement of the Southport and Roxboro facilities effective March 31, 2021 and lower dispatch at Arlington Valley, primarily in the third quarter of 2022. Arlington Valley also experienced a longer planned outage in the first half of 2022 compared with the same period in 2021 and an unplanned outage in the third quarter of 2022 compared with minimal outage hours in the same period in 2021.

Revenues and other income were higher in the three and nine months ended September 30, 2022 compared to the corresponding periods in 2021 primarily due to higher contracted variable revenues in 2022 at Decatur Energy as a result of higher generation and availability at that facility, as well as higher capacity revenue as a result of the extension to the tolling agreement that was previously announced in the third quarter of 2021 along with the increased capacity rating of the facility following the completion of upgrades in 2021. Additionally, Arlington Valley earned higher heat rate call option (HRCO) revenues driven by the impact of higher natural gas prices and higher market sales during the first two quarters of 2022, compared with the same period in 2021. The higher revenue and other income for the nine months ended September 30, 2022 compared with the same period in 2021 was partially offset by the retirement of the Southport and Roxboro facilities on March 31, 2021 and the revenue impact of the extreme weather event at Buckthorn Wind in February of 2021.

Adjusted EBITDA was higher in the three and nine months ended September 30, 2022 compared with 2021 primarily due to the impacts of the aforementioned revenue and other income variances, lower maintenance costs at Decatur due to no planned outage in 2022, and the retirement of the Southport and Roxboro facilities who contributed a negative adjusted EBITDA in the first quarter of 2021.

***Corporate***

Corporate results include (i) revenues for cost recoveries and other income related to off-coal compensation from the Province of Alberta, (ii) costs of support services such as treasury, finance, internal audit, legal, people services, corporate risk management, asset management, and environment, health and safety, and (iii) business development expenses. Note that cost recovery revenues are primarily intercompany revenues that are offset by interplant category transactions.

Net corporate revenues and other income were consistent in 2022 compared with 2021. Adjusted EBITDA for the three and nine months ended September 30, 2022 was lower than the comparable periods in 2021 mainly due to higher business development expenses, increased share-based incentive expenses as a result of increased share price, and the reversal of a contingent consideration provision in 2021 related to a previous acquisition that was no longer required.

***Unrealized changes in fair value of commodity derivatives and emission credits***

| (unaudited, $ millions) | **Three months ended September 30** | | | |
|---|---|---|---|---|
| | **2022** | **2021** | **2022** | **2021** |
| **Unrealized changes in fair value of commodity derivatives and emission credits** | **Revenues and other income** | | **Income before tax** | |
| Unrealized losses on Alberta power derivatives | (125) | (50) | (113) | (56) |
| Unrealized losses on U.S. power derivatives | (22) | (75) | (22) | (75) |
| Unrealized gains (losses) on natural gas derivatives | 54 | (53) | (3) | 64 |
| Unrealized gains (losses) on emission derivatives | 8 | (1) | 8 | (1) |
| Unrealized (losses) gains on emission credits held for trading | - | - | (6) | 2 |
| | **(85)** | **(179)** | **(136)** | **(66)** |

| (unaudited, $ millions) | **Nine months ended September 30** | | | |
|---|---|---|---|---|
| | **2022** | **2021** | **2022** | **2021** |
| **Unrealized changes in fair value of commodity derivatives and emission credits** | **Revenues and other income** | | **Income before tax** | |
| Unrealized losses on Alberta power derivatives | (205) | (72) | (186) | (52) |
| Unrealized losses on U.S. power derivatives | (110) | (159) | (110) | (159) |
| Unrealized (losses) gains on natural gas derivatives | (21) | (128) | 103 | 121 |
| Unrealized gains (losses) on emission derivatives | 22 | (10) | 22 | (10) |
| Unrealized (losses) gains on emission credits held for trading | - | - | (11) | 3 |
| | **(314)** | **(369)** | **(182)** | **(97)** |

The Company's revenues and other income and adjusted EBITDA relating to its Alberta commercial facilities and portfolio optimization, U.S. wind facilities and certain Alberta contracted renewables facilities include realized changes in the fair value of commodity derivatives and emission credits. Unrealized changes in the fair value of commodity derivatives and emission credits are excluded from revenues and other income relating to the noted portfolio and facilities and are also excluded from the Company's adjusted EBITDA metric.

When a derivative instrument settles, the unrealized fair value changes recorded in prior periods for that instrument are reversed from this category. The gain or loss realized upon settlement is then reflected in adjusted EBITDA for the applicable facility category.

During the three and nine months ended September 30, 2022, the Alberta power portfolio recognized unrealized losses on Alberta power derivatives of $113 million and $186 million respectively, due to the impact of increasing forward prices on net forward sale contracts, offset partly by the reversal of prior period unrealized losses on positions that settled during those periods. During the comparable periods in 2021, the Alberta power portfolio recognized unrealized losses of $56 million and $52 million respectively. This was due to the impact of increasing forward Alberta power prices on the value of forward purchase contracts, as well as the reversal of prior period unrealized gains on positions that settled during those periods.

During the three and nine months ended September 30, 2022, the U.S. power portfolio recognized unrealized losses of $22 million and $110 million respectively, as a result of the impact of increasing forward power prices on forward sale contracts associated with the Company's U.S. Wind facilities. During the comparable periods in 2021, the U.S.

power portfolio recognized unrealized losses of $75 million and $159 million respectively, due to the impact of increasing forward prices on forward sale contracts.

During the three months ended September 30, 2022, the Company recognized unrealized losses on natural gas derivatives of $3 million due primarily to the reversal of prior period unrealized gains on positions that settled during the quarter. During the nine months ended September 30, 2022, the Company recognized unrealized gains of $103 million due to the impact of increasing forward prices on forward purchase contracts, partially offset by the reversal of prior period unrealized gains on positions that settled during these periods. During the comparable periods in 2021, the Company recognized unrealized gains of $64 million and $121 million respectively, mainly as a result of increasing forward prices on forward purchase contracts.

During the three and nine months ended September 30, 2022, the Company recognized unrealized gains on emission derivatives of $8 million and $22 million respectively, due to both the reversal of prior period unrealized losses on positions that settled as well as the impact of increasing forward prices on forward purchase contracts. During the nine months ended September 30, 2021, unrealized losses on emission derivatives of $10 million were recognized as a result of increasing forward prices on forward sale contracts as well as the reversal of prior period unrealized gains on positions that settled during that period.

During the three and nine months ended September 30, 2022, the Company recognized unrealized losses of $6 million and $11 million on emission credits held for trading, due to the reversal of prior period unrealized gains on inventory sold during that time. During the comparable periods of 2021, unrealized gains on emission credits held for trading were the result of increasing market prices on portfolio holdings partially offset by the reversal of prior periods unrealized gains on emission credits sold.

## Consolidated other expenses and non-controlling interests

| (unaudited, $ millions) | **Three months ended September 30** | | **Nine months ended September 30** | |
|---|---|---|---|---|
| | **2022** | **2021** | **2022** | **2021** |
| Interest on borrowings less capitalized interest | (32) | (31) | (93) | (102) |
| Realized gains (losses) on settlement of non-hedged interest rate derivatives | 10 | (2) | 7 | (4) |
| Other net finance expense – interest on off-coal compensation from the Province of Alberta, lease liability interest, sundry interest, guarantee and other fees | (1) | - | (6) | (1) |
| | (23) | (33) | (92) | (107) |
| Unrealized (losses) gains representing changes in the fair value of interest rate derivatives | (8) | 1 | 6 | 10 |
| Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to off-coal compensation from the Province of Alberta | (9) | (11) | (26) | (33) |
| Total net finance expense | (40) | (43) | (112) | (130) |
| Depreciation and amortization | (133) | (133) | (414) | (402) |
| (Losses) gains on disposals and other transactions | (3) | 31 | (4) | 30 |
| Impairments, net of reversal | - | (8) | - | (6) |
| Foreign exchange loss | (12) | (7) | (18) | (8) |
| Finance expense and depreciation expense from joint ventures | (4) | (4) | (5) | (9) |
| Income tax expense | (24) | (18) | (88) | (52) |
| Net loss attributable to non-controlling interests | 3 | 2 | 9 | 7 |

### *Net finance expense*

Lower net finance expense for the nine months ended September 30, 2022 compared with the same period in the prior year largely reflects higher capitalized interest as a result of the continuing advancement of the Genesee repowering project and increased Enchant Solar capital spend, partially offset by higher interest on increased loans and borrowings outstanding during the period mainly due to the private placement of senior notes issued in the fourth quarter of 2021. Lower net finance expense year-to-date was also a result of lower accretion due to off-coal compensation and higher realized gains on the settlement of a non-hedge interest rate swaps related to the issuance of Subordinated Notes (see Significant Events) in the third quarter of 2022.

### *Depreciation and amortization*

Depreciation and amortization for the nine months ended September 30, 2022 increased compared with the same period in the prior year primarily due to phases 2 and 3 of Whitla Wind (commenced commercial operations in December 2021), Strathmore Solar (commenced commercial operations in March 2022, see Significant Events) and further shortened useful life of the Genesee Mine, partially offset by the classification of Island Generation EPA as a finance lease during the second quarter of 2022 (see Significant Events) and by Southport and Roxboro being fully depreciated as of the end of the first quarter of 2021.

***(Losses) gains on disposals and other transactions***

Gains on disposals and other transactions for the nine months ended September 30, 2021 reflects net gain of $16 million recorded in the second quarter of 2021 for accrued insurance recoveries, related expensed costs and capitalized costs incurred to date to repair Genesee 2. In addition, the Company recorded a gain of $7 million on decommission costs in the second quarter of 2021 to reflect lower decommissioning costs than what was previously established as provisions. The year-to-date amount in 2021 further reflects other gains on disposal, largely related to land sales.

***Impairments, net of reversal***

During the third quarter of 2021, the Company and its partner on the Genesee 4 and 5 project reached a settlement concerning the costs of exiting the series of previously executed agreements. As a result, the Company reversed the provision initially recorded to gains on disposals and other transactions during the second quarter of 2021 and recognized an impairment loss of $8 million on the Company's consolidated statements of income related to the assets acquired upon settlement.

For the nine months ended September 30, 2021, the Company also recognized a pre-tax impairment reversal of $2 million related to the discontinuation of the Genesee 4 and 5 project for which the Company previously recognized a pre-tax impairment of $13 million during the nine months ended September 30, 2020.

***Foreign exchange loss***

As at September 30, 2022, the Company had no outstanding foreign currency non-hedge purchase contracts. Foreign exchange loss in the year reflects losses incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes.

As at September 30, 2021, the Company had outstanding foreign currency non-hedge sale contracts totalling US$199 million. For the three and nine months ended September 30, 2021, the exchange rate of the Canadian dollar relative to the U.S. dollar weakened from the time the foreign currency sale contracts were entered resulting in an unrealized loss on the foreign currency sale contracts, partially offset by realized gains on the settlement of foreign currency sale contracts in the quarter.

***Finance expense and depreciation expense from joint ventures***

Finance expense and depreciation expense from joint ventures includes Capital Power's share of finance expense and depreciation expense of York Energy and Midland Cogen (see Significant Events), which are accounted for under the equity method. Finance expense and depreciation expense from joint ventures decreased by $5 million for the nine months ended September 30, 2022 compared with the same periods in 2021 driven by larger impacts of increasing interest rates resulting in higher gains on the non-hedge interest rate swaps held within the York Energy joint venture. Due to the proximity of the Midland Cogen acquisition closing date to September 30, 2022, the depreciation expense from the facility was not material in the quarter.

***Income tax expense***

For the three months ended September 30, 2022, income tax expense increased compared with the corresponding periods in 2021 primarily due to rate differences associated with foreign exchange movements, partially offset by a decrease in amounts attributable to tax-equity interests. Further, on a year-to-date basis, income tax expense increased due to higher overall consolidated net income before tax in 2022. In addition, Capital Power recognized a $10 million deferred income tax benefit in the prior period that was attributable to lower applicable jurisdictional tax rates, of which there is no comparable tax recovery recognized in 2022. The year-to-date increase is partially offset by a decrease in amounts attributable to tax-equity interests in 2022 compared to 2021.

***Non-controlling interests***

Non-controlling interests mostly consist of the Genesee Mine partner's share of the consolidated depreciation expense of the Genesee Mine.

## COMPREHENSIVE INCOME

| (unaudited, $ millions) | Three months ended September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| | 2022 | 2021 | 2022 | 2021 |
| Net income | 31 | 38 | 227 | 156 |
| Other comprehensive income (loss): | | | | |
| Actuarial gains related to the Company's defined benefit pension plans | - | - | 10 | - |
| Net unrealized losses on derivative instruments | (222) | (60) | (224) | (166) |
| Net realized losses on derivative instruments reclassified to net income | 165 | 39 | 217 | 125 |
| Unrealized foreign exchange gains on the translation of foreign operations | 73 | 28 | 96 | 10 |
| Total other comprehensive income (loss), net of tax | 16 | 7 | 99 | (31) |
| **Comprehensive income** | **47** | **45** | **326** | **125** |

Other comprehensive income (loss) includes fair value adjustments on financial instruments held by the Company to hedge market risks and which meet the requirements of hedges for accounting purposes. To the extent that such hedges are ineffective, any related gains or losses are recognized in net income. Other unrealized fair value changes on derivative instruments designated as cash flow hedges and foreign currency translation gains or losses are subsequently recognized in net income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated.

## FINANCIAL POSITION

The significant changes in the consolidated statements of financial position from December 31, 2021 to September 30, 2022 were as follows:

| (unaudited, $ millions) | September 30, 2022 | December 31, 2021 | Increase (decrease) | Primary other changes |
|---|---|---|---|---|
| Trade and other receivables[1] | 751 | 474 | 277 | Increased accrued receivables due to higher settled Alberta pool prices in September 2022 compared to December 2021, higher dispatch at Goreway, other receivables from U.S. trading activities and higher capacity revenues at Arlington Valley from tolling revenue compared to lower heat rate call option revenue at December 2021. |
| Finance lease receivable (including current portion) | 42 | - | 42 | Island Generation's new EPA (see Significant Events) is classified as a finance lease, resulting in the recognition of a finance lease receivable and some revenues being classified as finance lease income whereas the previous EPA was classified as an operating lease and presented within property, plant and equipment and depreciated. |
| Equity-accounted investments | 433 | 145 | 288 | Increase primarily due to the acquisition of Midland Cogen (see Significant Events). |
| Property, plant and equipment | 6,330 | 6,203 | 127 | Increase due to capital additions for Genesee 1 and 2 repowering, Strathmore Solar and Enchant Solar partially offset by the derecognition of Island Generation's net assets due to new EPA being classified as a finance lease (see Significant Events), the impact of increasing interest rates on decommissioning assets, foreign exchange impacts and depreciation. |
| Trade and other payables | 1,018 | 624 | 394 | Increase due to higher trading margin account payables due to margin account withdrawals resulting from increasing forward natural gas prices on net forward purchase contracts, |

| (unaudited, $ millions) | September 30, 2022 | December 31, 2021 | Increase (decrease) | Primary other changes |
|---|---|---|---|---|
| | | | | higher accrued emission compliance obligations due to increased generation and carbon compliance pricing, higher commodity purchases that settled against higher Alberta pool prices in September 2022 and higher natural gas accruals at Goreway due to higher generation and natural gas prices. |
| Net derivative financial instruments liabilities | 407 | 274 | 133 | Increase due the impact of increasing forward prices on forward sale contracts for our U.S. contracted wind and certain Alberta contracted renewable assets and increasing forward Alberta power prices on forward sale contracts, offset partly by reduction in interest rate swap liabilities resulting from increasing forward interest rates and the impact of increasing forward natural gas prices on net forward purchase contracts. |
| Loans and borrowings (including current portion) | 3,424 | 3,360 | 64 | Increase primarily due to issuance of Subordinated Notes (see Significant Events) offset by repayments of U.S. dollar bank loans and allocation of income tax benefits to tax-equity investors associated with the Company's tax-equity structures. |
| Provisions (including current portion) | 372 | 461 | (89) | Decrease mainly due to revisions to existing decommissioning provisions driven by increases in interest rates partly offset by additional share based incentive accrual as a result of increased share price. |
| Net deferred tax liabilities | 618 | 567 | 51 | Increase primarily due to recognition of taxable temporary differences that will reverse in the future, and changes in derivative financial instrument balances. |

[1] Excludes current portion of finance lease receivable.

## LIQUIDITY AND CAPITAL RESOURCES

| (unaudited, $ millions) | Nine months ended September 30 | | |
|---|---|---|---|
| Cash inflows (outflows) | 2022 | 2021 | Change |
| Operating activities | 893 | 682 | 211 |
| Investing activities | (726) | (367) | (359) |
| Financing activities | (337) | (397) | 60 |

### Operating activities

Cash flows from operating activities for the nine months ended September 30, 2022 increased compared with the same period in 2021 mainly due to:

- cash flow impacts of the increases in adjusted EBITDA described in Consolidated Net Income and Results of Operations, primarily attributable to higher generation and realized Alberta power pricing and strong results from our U.S. contracted facilities;
- favorable changes in non-cash working capital mainly driven by higher margin account withdrawals resulting from the impact of increasing forward natural gas prices on forward purchase contracts partly offset by increases in trade receivables primarily attributable to higher settled Alberta pool prices in September and higher generation;
- lower interest paid due to higher realized gains on the settlement of the Company's non-hedge interest rate swaps in the third quarter of 2022 and lower interest paid due to lower refinanced senior notes in the fourth quarter of 2021; and

- the net settlement of tranches 2 and 3 of the LLR Proceeding invoices in 2021 with no comparable impacts in 2022.

Partially offsetting the above increases are higher income taxes paid and unfavourable fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty for the nine months ended September 2022 compared with the same period in 2021, most notably driven by the impact of increasing forward power prices on net forward sale contracts in 2022.

### Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2022 increased compared with the same period in 2021 due to the Company's acquisition of a joint venture interest in Midland Cogen (see Significant Events) and higher cash capital expenditures, most notably increased spend on the repowering of Genesee 1 and 2 and Enchant Solar.

***Capital expenditures and investments***

| (unaudited, $ millions) | Pre-2022 actual | Nine months ended September 30, 2022 actual | Balance of 2022 estimated [1,2] | Actual or projected total [2] | Targeted completion |
|---|---|---|---|---|---|
| Repowering of Genesee 1 and 2 [3] | 238 | 297 | 116 | 1,192 | Unit 1 and Unit 2 in 2024 |
| Whitla Wind 2 and 3 | 242 | 2 | 8 | 252 | Operations commenced December 2021 |
| Strathmore Solar | 51 | 7 | - | 58 | Operations commenced March 2022 |
| Enchant Solar [4] | 19 | 87 | 18 | 124 | Fourth quarter of 2022 |
| Bear Branch Solar | 2 | 1 | 2 | 60 | Fourth quarter of 2024 |
| Hornet Solar | 2 | 1 | 3 | 118 | Fourth quarter of 2024 |
| Hunter's Cove Solar | 2 | - | 2 | 82 | Fourth quarter of 2024 |
| Commercial initiatives [5] | 182 | 6 | 7 | 208 | |
| Development sites and projects | 60 | 2 | - | | |
| **Subtotal growth projects** | | **403** | **156** | | |
| Sustaining – plant maintenance excluding Genesee Mine | | 79 | | | |
| **Total capital expenditures** [6] | | **482** | | | |
| Emission credits held for compliance | | 82 | | | |
| Capitalized interest | | (13) | | | |
| **Additions of property, plant and equipment and other assets** | | **551** | | | |
| Change in other non-cash investing working capital and non-current liabilities | | (48) | | | |
| **Purchase of property, plant and equipment and other assets, net** | | **503** | | | |

1 The Company's 2022 estimated capital expenditures include only expenditures for previously announced growth projects and exclude other potential new development projects.

2 Projected capital expenditures to be incurred over the life of the ongoing projects are based on management's estimates. Projected capital expenditures for development sites are not reflected beyond the current period until specific projects reach the advanced development stage.

3 Projected total costs include up to 210MW Genesee Battery Energy Storage System to be constructed as part of the repowering project. The battery storage addition will be going through the regulatory approval process with an anticipated in-service date of late 2024.

4 Projected total costs have increased from the original projected cost of $102 million for Enchant Solar due to supply chain pressures and significant increases in transportation costs.

5 Commercial initiatives include expected spending on the Company's Genesee dual-fuel project and the Genesee Performance Standard project as well as various other projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

6 Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the consolidated statements of cash flows as purchase of property, plant and equipment and other assets, net.

### Financing activities

Cash flows used in financing activities were lower in the nine months ended September 30, 2022 mainly due to higher cash inflows from the Company's Subordinated Notes (see Significant Events) issued during the third quarter of 2022 and lower net repayments of loans and borrowings in the current year due to the repayment of U.S dollar bank loans in the second quarter of 2021. This was offset by the redemption of the Company's Series 9 Shares (see Significant Events) in September 2022, higher common share dividends paid in 2022 as the Company's Dividend Reinvestment Plan was suspended in the fourth quarter of 2021 and the issuance of common shares in the prior year.

The Company's credit facilities consisted of:

| (unaudited, $ millions) | | As at September 30, 2022 | | | As at December 31, 2021 | | |
|---|---|---|---|---|---|---|---|
| | **Maturity timing** | **Total facilities** | **Credit facility utilization** | **Available** | **Total facilities** | **Credit facility utilization** | **Available** |
| Committed credit facilities | 2027 | 1,000 | | | 1,000 | | |
| Letters of credit outstanding | | | - | | | 30 | |
| Bankers' acceptances outstanding | | | - | | | - | |
| Bank loans outstanding [1] | | | - | | | 241 | |
| | | 1,000 | - | 1,000 | 1,000 | 271 | 729 |
| Bilateral demand credit facilities | N/A | 1,214 | | | 773 | | |
| Letters of credit outstanding | | | 963 | | | 465 | |
| | | 1,214 | 963 | 251 | 773 | 465 | 308 |
| Demand credit facilities | N/A | 25 | - | 25 | 25 | - | 25 |
| | | **2,239** | **963** | **1,276** | **1,798** | **736** | **1,062** |

1 U.S. dollar denominated bank loans outstanding totaling nil (December 31, 2021 – US$191 million).

As at September 30, 2022, the committed credit facility utilization decreased $271 million compared with the utilization at December 31, 2021, due to repayment of U.S. dollar bank loans. The available credit facilities provide the Company with adequate funding for ongoing development projects. During the third quarter of 2022, the $1 billion of committed credit facilities were extended 1 year to mature in July 2027.

The Company has a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P) which was affirmed in their latest report, published in April 2022. The BBB rating category assigned by S&P is the fourth highest rating of S&P's ten rating categories for long-term debt obligations. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments, however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

The Company has a corporate credit rating of BBB (low) with a stable trend from DBRS Limited (DBRS), which was affirmed in their latest report, published in April 2022. The BBB rating category assigned by DBRS is the fourth highest rating of DBRS's ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality and the capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.

The above credit ratings from S&P and DBRS are investment grade credit ratings which enhance Capital Power's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

## Future cash requirements

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's expected cash requirements for 2022 include:

| (unaudited, $ millions) | Nine months ended September 30, 2022 actual | Balance of 2022 estimated | Total 2022 expected cash requirements |
|---|---|---|---|
| Repayment of debt payable [1] | 55 | 11 | 66 |
| Interest on loans and borrowings | 76 | 23 | 99 |
| Capital expenditures – sustaining | 75 | 62 | 137 |
| Capital expenditures – ongoing growth projects [2] | 349 | 149 | 498 |
| Capital expenditures – commercial initiatives | 6 | 7 | 13 |
| Common share dividends [3] | 191 | 71 | 262 |
| Preferred share dividends | 29 | 8 | 37 |
| | **781** | **331** | **1,112** |

1 Excludes repayment of credit facilities.

2 Excludes capital expenditures on the Genesee 1 and 2 repowering project for which payments are deferred.

3 Includes 6% annual dividend growth (see Significant Events).

The Company uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital when required. Under the short-form base shelf prospectus, Capital Power may issue an unlimited number of common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities, including up to $2 billion of medium-term notes by way of a prospectus supplement. This prospectus expires in July 2024.

If the Canadian and U.S. financial markets become unstable, Capital Power's ability to raise new capital, to meet its financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. Capital Power has credit exposure relating to various agreements, particularly with respect to its power purchase agreement or arrangement (PPA), energy supply contract, trading and supplier counterparties. While Capital Power continues to monitor its exposure to its significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments. See Risks and Risk Management for additional discussion on recent developments pertaining to these risks.

## Off-statement of financial position arrangements

At September 30, 2022, the Company has $963 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements and to satisfy legislated reclamation requirements. If the Company were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

## Capital resources

| (unaudited, $ millions) | As at | |
|---|---|---|
| | **September 30, 2022** | **December 31, 2021** |
| Loans and borrowings | 3,424 | 3,360 |
| Lease liabilities [1] | 148 | 143 |
| Less cash and cash equivalents | (211) | (387) |
| Net debt | 3,361 | 3,116 |
| Share capital | 3,497 | 3,631 |
| Deficit and other reserves | (681) | (790) |
| Non-controlling interests | 8 | 18 |
| Total equity | 2,824 | 2,859 |
| **Total capital** | **6,185** | **5,975** |

1 Includes the current portion presented within deferred revenue and other liabilities.

## CONTINGENT LIABILITIES, OTHER LEGAL MATTERS AND PROVISIONS

Refer to Contractual Obligations, Contingent Liabilities, Other Legal Matters and Provisions discussion in the Company's 2021 Integrated Annual Report for details on ongoing legal matters for which there were no notable updates in the current period.

### Contingent liabilities

The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

### Line Loss Rule Proceeding

On May 31, 2022, an Alberta Government bill was passed with the intent to dissolve the Balancing Pool. Capital Power continues to expect that it will ultimately realize the full amount of the gross receivables related to line losses upon resolution of the dispute before the Court whether it be from the Balancing Pool or the designated entity assuming its residual responsibilities as will be identified in forthcoming amendments to provincial regulation enacting the dissolution.

## RISKS AND RISK MANAGEMENT

For the nine months ended September 30, 2022, the Company's business and operational risks have remained consistent with those described in the Company's 2021 Integrated Annual Report. Information pertaining to climate-related risks and opportunities can be found on the Company's website within its 2021 Climate Change Disclosure Report.

Details around the Company's approach to risk management, including the Company's principal risk factors and the associated risk mitigation strategies, are described in the Company's 2021 Integrated Annual Report. These factors and strategies have not changed materially in the nine months ended September 30, 2022, however the Company continues to see an increase in supply chain risks including those described below.

The Russian government's invasion of Ukraine on February 24, 2022 set off historic policy actions and global coordination of sanctions and commitments to reduce dependency on Russian energy including natural gas. This has contributed to global supply chain disruptions, commodity price volatility and potential increases to inherent cybersecurity risk. We continue to mitigate supply chain risk pertaining to current development projects by locking in the prices of key materials where possible and employing the other supply chain risk mitigation strategies described in our 2021 Integrated Annual Report. A prolonged Russia-Ukraine conflict could impact future construction project costs with the risk of rising prices on key materials. The Russia-Ukraine conflict continues to evolve as well as the scope and severity of the economic sanctions. Accordingly, the indirect impacts of the Russia-Ukraine conflict transpiring through the global markets to the Company remains uncertain at this time, but management continues to monitor and assess the resulting impacts.

## ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $281 million at September 30, 2022 ($366 million as at December 31, 2021) for its generation facilities and the Genesee Mine as it is obliged to remove the facilities at the end of their useful lives and restore the facility and mine sites to their original condition. Decommissioning provisions for the Genesee Mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could vary and the amount of decommissioning provisions could change depending on potential future changes in environmental regulations and the timing of any facility fuel conversions.

The Company has forward contracts to purchase environmental credits totaling $672 million and forward contracts to sell environmental credits totaling $473 million in future years. Included within these forward purchases and sales are net purchase amounts which will be used by the Company to comply with applicable environmental regulations and net sales amounts related to other emissions trading activities.

## REGULATORY MATTERS

Refer to Regulatory Matters discussion in the Company's 2021 Integrated Annual Report for further details that supplement the recent developments discussed below:

### Canada

Further to the climate plan and emission reduction announcements released by the Government of Canada as discussed in the Company's 2021 Integrated Annual Report, Environment and Climate Change Canada (ECCC) released a Clean Electricity Standard (CES) Discussion Paper on March 15, 2022.

The Discussion Paper described the intended role for a CES as part of a broader suite of policies intended to achieve the Federal Government's objective of achieving a net-zero electricity system by 2035. The Discussion Paper invites input on the scope and design for a CES and related issues including, among other things, the level for a CES, the scope of compliance flexibility, and the role of natural gas generation. The Discussion Paper also affirms the Federal Government's intention to collaborate with provinces, territories and stakeholders to ensure the design of the CES provides a clear and workable basis for provinces and territories to be able to plan and operate their electricity systems in a way that will continue to reliably deliver affordable electricity to Canadians.

Capital Power provided comments regarding the Discussion Paper in April 2022. Capital Power's comments highlighted the importance of recognizing a continued role for some natural gas generation in order to support reliability and affordability objectives, though this will vary by province, and the need for the timing and nature of any reasonable CES compliance obligations to differentiate between existing and new generating units, and between baseload and peaking units. The importance of ensuring the design of CES took into account regional differences, particularly Alberta's competitive market framework, was highlighted, along with the need for a CES compliance framework to ensure flexibility to use a full portfolio of approaches, including offsets.

On July 26, ECCC released a Proposed Frame for the Clean Electricity Regulation (the Proposed Frame), setting out the key elements of the potential performance standard framework that ECCC is proposing based on feedback received on the Discussion Paper. The Proposed Frame recognizes the continued role that natural gas generation will have in supporting reliability and integrating renewables through the net-zero electricity supply by 2035 transition and beyond. It would subject new units - defined as those commissioned in 2025 or after - to the CES on January 1, 2035, while existing units would be subject to the CES at the end of their "prescribed life" or January 1, 2035. The definition of prescribed life will be developed as part of continued consultations. The Proposed Frame would allow natural gas units to continue to operate post-prescribed life subject to undefined caps on annual emissions and run-time, and would also subject cogeneration units to the CES in respect of net-to-grid generation.

Based on management's review of the Proposed Frame, Capital Power's entire Alberta natural gas generation fleet, including Genesee 1 and 2 repowering, would qualify as "existing" units, and every unit would only be subject to the CES at the end of its prescribed life or 2035. The Proposed Frame's acknowledgement of a long-term role for natural gas generation, including the provisions for post-prescribed life, within a net-zero framework is also notable.

Capital Power continues to participate in ECCC's process to develop the CES framework.

In 2022, the Federal Government is also undertaking an assessment of the equivalency of provincial carbon pricing frameworks, including Alberta's Technology, Innovation and Emission Reduction (TIER) framework, with the Federal Output Based Pricing System (OBPS) backstop framework. This review will consider all aspects of Alberta's TIER regime, and not only the TIER electricity regime. The equivalency determination will be made before the end of 2022 and 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 2027-30 period. The equivalency review was initiated prior to the launch of the CES consultations, and it is unclear at this time to what extent, if at all, the CES consultations will impact the 2022 equivalency review. As discussed below, Alberta has initiated consultations regarding potential changes to the TIER framework that Alberta expects will maintain equivalency with the Federal backstop framework and preserve provincial jurisdiction over carbon pricing.

On March 29, 2022, the Government of Canada released its inaugural Emissions Reduction Plan (ERP) as required under the *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. Such mechanisms could support the Company's consideration and assessment of the Genesee CCS Project and other initiatives.

On April 7, 2022, the Government of Canada tabled Budget 2022. Among the measures included with respect to supporting clean energy deployment, the Government proposed a refundable ITC for investment in CCUS projects. From 2022 – 2030, the proposed ITC rates would be set at 60% for investment in direct air capture projects, 50% for investment in all other CCUS projects, and 37.5% for investment in transportation, storage and use. The rates would be reduced by 50% for the period from 2031 – 2040. In August 2022, Federal Finance issued Draft Legislation with the proposed provisions and terms for implementing the CCUS ITC. The proposed ITC framework is directionally positive for the Genesee CCS Project, though other mechanisms of policy support continue to be required to address certain financing and policy-uncertainty risks and challenges faced by the Project.

Management continues to assess the potential impacts that the proposed elements of the updated CES and the Plan may have for Capital Power's existing facilities and prospective interests in its Canadian markets and intends to participate in forthcoming processes.

### Alberta

As discussed in the Company's 2021 Integrated Annual Report, the AESO initiated consultation on the most severe single contingency (MSSC) limit of 466 MW and whether this limit should remain at the current level or increase. The current limit impacts the Genesee repowering project as each combined cycle unit (680 MW) would exceed the current limit. The Company has announced plans to install battery storage in conjunction with the Genesee repowering project to alleviate any constraints the existing MSSC limit may present. The AESO issued an options paper on the issue and presented it to stakeholders in October, with consultation occurring through to the end of the year. The Company will be participating in the AESO consultation process and is supportive of the AESO increasing the MSSC limit.

Alberta Environment and Parks (AEP) launched the formal review of the TIER Regulation through a discussion paper released on June 17, 2022. The Discussion Paper noted Alberta's intention to achieve equivalence with the Federal benchmark criteria in order to preserve provincial jurisdiction of the carbon pricing framework for large emitters. The Discussion Paper identified potential changes to various aspects of the TIER framework that, collectively, AEP believes will meet the equivalency threshold as it is being defined by ECCC. The key changes proposed in the Discussion Paper 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 (including the 0.37 t/MWh performance standard of the electricity TIER) until 2030, aligning the Electricity Grid Displacement Factor used as the basis for offsets with the electricity TIER benchmark, and potentially increasing the offset utilization cap from the current level of 60%. Capital Power provided comments in August 2022 that supported the proposed 2% per year increase in electricity benchmark stringency as part of the proposed package of sector-wide changes. AEP is targeting to finalize the recommendations by fall of 2022 and have the enabling regulations completed by December 31, 2022.

### Ontario

In August 2022, the Ontario Ministry of Environment, Conservation and Parks (MECP) issued for consultation proposed changes to the Emissions Performance Standards (EPS) program for 2023-2030 to meet the benchmark set by the federal government. Under the proposed EPS, the performance standard that currently applies to electricity generation using fossil fuels will change from 0.370 tCO2e/MWh to 0.31 tCO2e/MWh. Starting in 2023, the proposed electricity benchmark will be 0.31 tCO2e/MWh and remain constant until 2030. Management continues to assess the potential impacts of the proposed amendments to the EPS, and will participate in the MECP consultation process. The contracts for Capital Power'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

The Inflation Reduction Act of 2022 (IRA) represents the most significant legislation to invest in clean energy and address climate change in US history. Passed by Congress and signed into law in August of 2022, the IRA puts the United States on a projected path to reduce greenhouse gas emissions 40 percent 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 Inflation Reduction Act implementation. On October 5, 2022, Treasury and the IRS issued a set of Notices requesting public comment on implementing key provisions. The Notices seek initial input from the public on specific questions, as well as requests for general comments. Stakeholders are encouraged to respond as soon as possible, ideally within 30 days of issuance (by November 4, 2022). Responses will inform Treasury and the IRS' implementation of this landmark legislation. Management will need to carefully monitor the risks and opportunities implementation of these provisions provide to our existing commercial assets as well as the portfolio of solar projects undergoing due diligence and business development. Further the increase in zero emission regulatory incentives may increase pressure on thermal based assets over time.

In June of 2022, the U.S. Supreme Court ruled in West Virginia v. Environmental Protection Agency (EPA) that EPA exceeded its statutory authority under the Clean Air Act in promulgating the Obama-era Clean Power Plan. The majority held that EPA failed to demonstrate clear Congressional authorization to undertake generation shifting, as required by the Clean Power Plan, that would reshape the US electric grid.

The Clean Power Plan would have permitted compliance with CO2 standards through either efficiency improvements on-site at power plants or through generation shifting to natural gas power plants or wind and solar facilities. President Biden criticized the Supreme Court's decision but stated that he "would take action" to address climate change, indicating that he was directing EPA and the Justice Department to take all legal options to reduce CO2 emissions.

EPA Administrator Michael Regan also called the ruling a setback but underscored that EPA will move forward in exercising existing legal tools to address climate change. Accordingly, in September EPA opened a public docket to accept pre-proposal input on EPA's efforts to reduce emissions of greenhouse gases (GHGs) from new and existing fossil fuel-fired electric generating units (EGUs). The goal of this non-rulemaking docket is to gather perspectives from a broad group of stakeholders in advance of proposed rulemakings in 2023. These proposed rulemakings will be important U.S. Government actions to mitigate the emission of GHGs to address the challenges of climate change and may impact emissions at our natural gas facilities and more broadly other communities with environmental justice concerns.

Management continues to monitor these developments closely as they progress as they could have significant impacts on Capital Power.

## USE OF JUDGMENTS AND ESTIMATES

In preparing the condensed interim consolidated financial statements, management made judgments, estimates and assumptions that affect the application of the Company's accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from these estimates. There have been no significant changes to the Company's use of judgments and estimates as described in the Company's Integrated Annual Report.

## FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at September 30, 2022 and December 31, 2021 were as follows:

| (unaudited, $ millions) | | September 30, 2022 | | December 31, 2021 | |
|---|---|---|---|---|---|
| | **Fair value hierarchy level [1]** | **Carrying amount** | **Fair value** | **Carrying amount** | **Fair value** |
| **Financial assets:** | | | | | |
| Amortized cost | | | | | |
| Cash and cash equivalents | N/A | 211 | 211 | 387 | 387 |
| Trade and other receivables [2] | N/A | 694 | 694 | 419 | 419 |
| Government grant receivable [3] | Level 2 | 364 | 318 | 404 | 395 |
| Fair value through income or loss | | | | | |
| Derivative financial instruments assets – current and non-current | See below | 445 | 445 | 313 | 313 |
| Fair value through other comprehensive income | | | | | |
| Derivative financial instruments assets – current and non-current | See below | 64 | 64 | 17 | 17 |
| **Financial liabilities:** | | | | | |
| Other financial liabilities | | | | | |
| Trade and other payables | N/A | 1,018 | 1,018 | 624 | 624 |
| Loans and borrowings [3] | Level 2 | 3,424 | 3,277 | 3,360 | 3,515 |
| Fair value through income or loss | | | | | |
| Derivative financial instruments liabilities – current and non-current | See below | 736 | 736 | 440 | 440 |
| Fair value through other comprehensive income | | | | | |
| Derivative financial instruments liabilities – current and non-current | See below | 180 | 180 | 164 | 164 |

1 Fair values for Level 1 financial assets and liabilities are based on unadjusted quoted prices in active markets for identical instruments while fair values for Level 2 financial assets and liabilities are generally based on indirectly observable prices. The determination of fair values for Level 3 financial assets and liabilities is prepared by appropriate subject matter experts and reviewed by the Company's commodity risk group and by management.

2 Excludes current portion of government grant receivable and finance lease receivable.

3 Includes current portion.

## Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2022 to the Company's risk management and hedging activities as described in the Company's 2021 Integrated Annual Report.

The derivative financial instruments assets and liabilities held at September 30, 2022 compared with December 31, 2021 and used for risk management purposes were measured at fair value and consisted of the following:

| (unaudited, $ millions) | | September 30, 2022 | | | | |
|---|---|---|---|---|---|---|
| | Fair value hierarchy level | Commodity cash flow hedges | Commodity non-hedges | Interest rate cash flow hedges | Interest rate non-hedges | Total |
| Derivative financial instruments assets | Level 2 | 17 | 412 | 47 | 14 | 490 |
| | Level 3 | - | 19 | - | - | 19 |
| | | 17 | 431 | 47 | 14 | 509 |
| Derivative financial instruments liabilities | Level 2 | (160) | (339) | (20) | - | (519) |
| | Level 3 | - | (397) | - | - | (397) |
| | | (160) | (736) | (20) | - | (916) |
| **Net derivative financial instruments (liabilities) assets** | | **(143)** | **(305)** | **27** | **14** | **(407)** |

| (unaudited, $ millions) | | December 31, 2021 | | | | |
|---|---|---|---|---|---|---|
| | Fair value hierarchy level | Commodity cash flow hedges | Commodity non-hedges | Interest rate cash flow hedges | Interest rate non-hedges | Total |
| Derivative financial instruments assets | Level 2 | 7 | 290 | 10 | 9 | 316 |
| | Level 3 | - | 14 | - | - | 14 |
| | | 7 | 304 | 10 | 9 | 330 |
| Derivative financial instruments liabilities | Level 2 | (93) | (241) | (71) | (1) | (406) |
| | Level 3 | - | (198) | - | - | (198) |
| | | (93) | (439) | (71) | (1) | (604) |
| **Net derivative financial instruments (liabilities) assets** | | **(86)** | **(135)** | **(61)** | **8** | **(274)** |

## Commodity, interest rate and foreign exchange derivatives designated as accounting hedges

Unrealized gains and losses for fair value changes on commodity, interest rate and foreign exchange derivatives that qualify for hedge accounting are recorded in other comprehensive income (loss) and, when realized, are reclassified to net income as revenues, energy purchases and fuel, finance expense or foreign exchange gains and losses as appropriate. When interest rate derivatives are used to hedge the interest rate on a future debt issuance, realized gains or losses are deferred within accumulated other comprehensive income (loss) and recognized within finance expense over the life of the debt, consistent with the interest expense on the hedged debt. When foreign exchange derivatives are used to hedge the risk of variability in cash flows resulting from foreign currency exchange rate fluctuations on future capital expenditures, realized gains and losses are deferred within accumulated other comprehensive income (loss) and then recorded in property, plant and equipment and amortized through depreciation and amortization over the estimated useful life of the hedged property, plant and equipment.

## Commodity, interest rate and foreign exchange derivatives not designated as accounting hedges

The change in fair values of commodity derivatives not designated as hedges is primarily due to changes in forward Alberta power and natural gas prices and their impact on the Alberta portfolio as well as the change in pricing on U.S. trading relating to the swap arrangements on the Company's U.S. wind generation. Unrealized and realized gains and losses for fair value changes on commodity derivatives that do not qualify for hedge accounting are recorded in net income as revenues or energy purchases and fuel.

Unrealized and realized gains and losses on foreign exchange derivatives and interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as foreign exchange gains or losses and net finance expense, respectively.

## DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no significant changes in the Company's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2022 that have materially affected or are reasonably likely to materially affect the Company's disclosures of required information and internal control over financial reporting.

## SUMMARY OF QUARTERLY RESULTS

| (GWh) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Electricity generation** | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| Total generation | 6,993 | 6,638 | 6,893 | 6,103 | 6,103 | 4,975 | 5,630 | 6,445 |
| **Alberta commercial facilities[1]** | | | | | | | | |
| Genesee 1 | 863 | 733 | 790 | 877 | 824 | 708 | 616 | 807 |
| Genesee 2 | 803 | 843 | 817 | 259 | 156 | 701 | 581 | 791 |
| Genesee 3 | 988 | 1,010 | 980 | 1,006 | 1,009 | 951 | 904 | 928 |
| Clover Bar Energy Centre 1, 2 and 3 | 218 | 72 | 112 | 135 | 235 | 67 | 23 | 112 |
| Joffre | 135 | 187 | 209 | 136 | 166 | 180 | 203 | 209 |
| Shepard | 824 | 814 | 786 | 714 | 739 | 379 | 803 | 839 |
| Halkirk Wind | 87 | 124 | 150 | 145 | 98 | 111 | 151 | 150 |
| Clover Bar Landfill Gas | 2 | 3 | - | - | - | - | - | - |
| | 3,920 | 3,786 | 3,844 | 3,272 | 3,227 | 3,097 | 3,281 | 3,836 |
| **Western Canada contracted facilities[1,2]** | | | | | | | | |
| Island Generation | - | - | 7 | 16 | 424 | 114 | 28 | 4 |
| Quality Wind | 93 | 70 | 126 | 130 | 101 | 83 | 127 | 128 |
| EnPower | 2 | 4 | 8 | 6 | - | 7 | 11 | 8 |
| Whitla Wind | 238 | 349 | 436 | 307 | 156 | 178 | 235 | 258 |
| Strathmore Solar[3] | 26 | 26 | 3 | N/A | N/A | N/A | N/A | N/A |
| | 359 | 449 | 580 | 459 | 681 | 382 | 401 | 398 |
| **Ontario contracted facilities[2]** | | | | | | | | |
| York Energy | 8 | 6 | 8 | 4 | 6 | 5 | 4 | 3 |
| East Windsor | 6 | 3 | 3 | 3 | 4 | 4 | - | 1 |
| Goreway | 721 | 234 | 599 | 383 | 453 | 159 | 234 | 279 |
| Kingsbridge 1 | 14 | 23 | 35 | 32 | 13 | 20 | 30 | 36 |
| Port Dover and Nanticoke | 50 | 67 | 100 | 81 | 47 | 66 | 81 | 95 |
| | 799 | 333 | 745 | 503 | 523 | 254 | 349 | 414 |
| **U.S. contracted facilities** | | | | | | | | |
| Roxboro, North Carolina[4] | N/A | N/A | N/A | N/A | N/A | N/A | 57 | 81 |
| Southport, North Carolina[4] | N/A | N/A | N/A | N/A | N/A | N/A | 60 | 95 |
| Decatur Energy, Alabama | 785 | 752 | 617 | 789 | 381 | 240 | 356 | 369 |
| Arlington Valley, Arizona | 685 | 659 | 476 | 501 | 876 | 461 | 545 | 644 |
| Beaufort Solar, North Carolina | 8 | 9 | 6 | 6 | 8 | 8 | 6 | 6 |
| Bloom Wind, Kansas | 126 | 208 | 180 | 147 | 132 | 177 | 165 | 179 |
| Macho Springs Wind, New Mexico | 17 | 48 | 34 | 30 | 15 | 41 | 38 | 30 |
| New Frontier Wind, North Dakota | 83 | 116 | 122 | 126 | 92 | 93 | 103 | 120 |
| Cardinal Point Wind, Illinois | 86 | 167 | 196 | 177 | 93 | 141 | 170 | 170 |
| Buckthorn Wind, Texas | 64 | 111 | 93 | 93 | 75 | 81 | 99 | 103 |
| Midland Cogen, Michigan[5] | 61 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | 1,915 | 2,070 | 1,724 | 1,869 | 1,672 | 1,242 | 1,599 | 1,797 |

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, as of January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative periods reflect power sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

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

3 Strathmore Solar was commissioned on March 17, 2022.

4 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations.

5 Midland Cogen was acquired on September 23, 2022 (see Significant Events).

| (%) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Facility availability** | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| Total average facility availability | 96 | 92 | 95 | 89 | 91 | 84 | 96 | 97 |
| **Alberta commercial facilities [1]** | | | | | | | | |
| Genesee 1 | 99 | 86 | 93 | 100 | 94 | 92 | 92 | 96 |
| Genesee 2 | 93 | 100 | 95 | 29 | 19 | 100 | 100 | 98 |
| Genesee 3 | 99 | 100 | 99 | 100 | 99 | 95 | 95 | 93 |
| Clover Bar Energy Centre 1, 2 and 3 | 93 | 89 | 87 | 83 | 97 | 94 | 99 | 91 |
| Joffre | 81 | 96 | 100 | 82 | 92 | 95 | 100 | 99 |
| Shepard | 98 | 100 | 100 | 99 | 100 | 50 | 100 | 100 |
| Halkirk Wind | 94 | 98 | 97 | 98 | 96 | 98 | 98 | 97 |
| Clover Bar Landfill Gas | 69 | 74 | 92 | 75 | 24 | - | - | - |
| | 95 | 96 | 96 | 84 | 83 | 87 | 97 | 96 |
| **Western Canada contracted facilities [1, 2]** | | | | | | | | |
| Island Generation | 100 | 100 | 100 | 97 | 96 | 89 | 100 | 100 |
| Quality Wind | 99 | 98 | 93 | 97 | 96 | 98 | 97 | 97 |
| EnPower | 92 | 99 | 99 | 98 | 100 | 93 | 89 | 98 |
| Whitla Wind | 92 | 97 | 98 | 97 | 95 | 98 | 98 | 99 |
| Strathmore Solar [3] | 100 | 100 | 100 | N/A | N/A | N/A | N/A | N/A |
| | 96 | 99 | 98 | 97 | 96 | 94 | 98 | 99 |
| **Ontario contracted facilities [2]** | | | | | | | | |
| York Energy | 96 | 100 | 100 | 89 | 87 | 100 | 100 | 100 |
| East Windsor | 93 | 76 | 97 | 88 | 100 | 100 | 99 | 94 |
| Goreway | 100 | 59 | 100 | 91 | 100 | 89 | 99 | 95 |
| Kingsbridge 1 | 96 | 99 | 98 | 99 | 99 | 98 | 99 | 100 |
| Port Dover and Nanticoke | 90 | 99 | 99 | 97 | 90 | 99 | 99 | 98 |
| | 98 | 71 | 99 | 91 | 97 | 93 | 99 | 96 |
| **U.S. contracted facilities** | | | | | | | | |
| Roxboro, North Carolina [4] | N/A | N/A | N/A | N/A | N/A | N/A | 100 | 100 |
| Southport, North Carolina [4] | N/A | N/A | N/A | N/A | N/A | N/A | 100 | 99 |
| Decatur Energy, Alabama | 98 | 100 | 94 | 82 | 94 | 51 | 79 | 100 |
| Arlington Valley, Arizona | 97 | 96 | 78 | 99 | 100 | 78 | 99 | 96 |
| Beaufort Solar, North Carolina | 100 | 99 | 100 | 98 | 96 | 97 | 99 | 98 |
| Bloom Wind, Kansas | 95 | 94 | 94 | 90 | 90 | 98 | 95 | 99 |
| Macho Springs Wind, New Mexico | 97 | 98 | 97 | 98 | 97 | 98 | 98 | 98 |
| New Frontier Wind, North Dakota | 94 | 95 | 96 | 97 | 95 | 97 | 94 | 93 |
| Cardinal Point Wind, Illinois | 96 | 98 | 95 | 99 | 96 | 97 | 99 | 97 |
| Buckthorn Wind, Texas | 92 | 90 | 92 | 94 | 96 | 94 | 94 | 96 |
| Midland Cogen, Michigan [5] | 86 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | 96 | 97 | 90 | 91 | 96 | 72 | 90 | 98 |

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, as of January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative periods reflect power sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

2 During the first quarter of 2021, management reviewed its facility groupings as a result of the change in classification of Genesee 1 and 2 as well as recent internal organizational changes. To best reflect how the Company operates, as of January

1, 2021, the British Columbia and Alberta contracted facilities are reported together as Western Canada contracted facilities with the Ontario contracted facilities in a separate grouping. Comparative figures have been reclassified to conform to the current period's presentation.

3 Strathmore Solar was commissioned on March 17, 2022.

4 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations.

5 Midland Cogen was acquired September 23, 2022 (see Significant Events).

## Financial results

| (unaudited, $ millions) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| **Revenues and other income** | | | | | | | | |
| Alberta commercial facilities and portfolio optimization[1] | 573 | 423 | 456 | 380 | 313 | 314 | 343 | 245 |
| Western Canada contracted facilities [1,2] | 29 | 30 | 50 | 43 | 28 | 25 | 37 | 38 |
| Ontario contracted facilities [2] | 126 | 89 | 104 | 88 | 82 | 66 | 80 | 84 |
| U.S. contracted facilities | 110 | 122 | 104 | 97 | 101 | 86 | 118 | 112 |
| Corporate [3] | 33 | 33 | 32 | 32 | 32 | 32 | 30 | 19 |
| Unrealized changes in fair value of commodity derivatives and emission credits | (85) | 16 | (245) | 32 | (179) | (136) | (54) | 18 |
| | **786** | **713** | **501** | **672** | **377** | **387** | **554** | **516** |
| **Adjusted EBITDA [5]** | | | | | | | | |
| Alberta commercial facilities and portfolio optimization[1] | 234 | 182 | 192 | 172 | 132 | 136 | 165 | 99 |
| Western Canada contracted facilities[1, 2] | 17 | 20 | 40 | 34 | 20 | 18 | 29 | 31 |
| Ontario contracted facilities [2,4] | 59 | 56 | 65 | 57 | 53 | 49 | 57 | 61 |
| U.S. contracted facilities[4] | 92 | 67 | 53 | 35 | 85 | 35 | 55 | 47 |
| Corporate | (19) | (6) | (2) | (4) | (4) | 3 | (3) | (18) |
| | **383** | **319** | **348** | **294** | **286** | **241** | **303** | **220** |

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, as of January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative periods reflect power sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

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

3 Revenues are offset by interplant category revenue eliminations

4 Includes adjusted EBITDA from the York Energy and Midland Cogen (See Significant Events) joint ventures.

5 Adjusted EBITDA is a non-GAAP financial measure (see Non-GAAP Financial Measures and Ratios).

Quarterly revenues, net income and cash flows from operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, and planned and unplanned facility outages and items outside the normal course of operations. Net income (loss) is also affected by changes in the fair value of the Company's power, natural gas, interest rate and foreign exchange derivative contracts.

## Financial highlights

| (unaudited, $ millions except per share amounts) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| Revenues and other income | 786 | 713 | 501 | 672 | 377 | 387 | 554 | 516 |
| Adjusted EBITDA [1, 2] | 383 | 319 | 348 | 294 | 286 | 241 | 303 | 220 |
| Net income (loss) | 31 | 77 | 119 | (69) | 38 | 17 | 101 | 1 |
| Net income (loss) attributable to shareholders of the Company | 34 | 80 | 122 | (65) | 40 | 20 | 103 | 3 |
| Basic earnings (loss) per share ($) | 0.21 | 0.59 | 0.96 | (0.67) | 0.23 | 0.05 | 0.83 | (0.09) |
| Diluted earnings (loss) per share ($)[3] | 0.20 | 0.59 | 0.96 | (0.67) | 0.23 | 0.05 | 0.83 | (0.09) |
| Normalized earnings per share ($) [1] | 1.25 | 0.76 | 0.93 | 0.47 | 0.55 | 0.32 | 0.64 | 0.12 |
| Net cash flows from operating activities | 370 | 108 | 415 | 185 | 347 | 129 | 206 | 159 |
| Adjusted funds from operations [1] | 328 | 180 | 200 | 149 | 206 | 91 | 159 | 86 |
| Adjusted funds from operations per share ($) [1] | 2.81 | 1.55 | 1.72 | 1.28 | 1.78 | 0.83 | 1.49 | 0.81 |
| Purchase of property, plant and equipment and other assets, net | 224 | 147 | 132 | 198 | 176 | 151 | 97 | 65 |

1 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings per share, AFFO and AFFO per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.

2 Includes adjusted EBITDA from the York Energy and Midland Cogen (see Significant Events) joint ventures.

3 Diluted earnings (loss) per share was calculated after giving effect to outstanding share purchase options.

| | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Spot price averages** | **Sep 2022** | **Jun 2022** | **Mar 2022** | **Dec 2021** | **Sep 2021** | **Jun 2021** | **Mar 2021** | **Dec 2020** |
| Alberta power ($ per MWh) | 221 | 122 | 90 | 107 | 100 | 105 | 95 | 46 |
| Alberta natural gas (AECO) ($ per GJ) | 4.02 | 6.86 | 4.54 | 4.48 | 3.32 | 3.03 | 3.07 | 2.52 |
| Capital Power's Alberta portfolio average realized power price ($ per MWh) | 101 | 85 | 84 | 84 | 75 | 75 | 77 | 56 |

## Factors impacting results for the previous quarters

Significant events and items which affected results for the previous quarters were as follows:

For the quarter ended June 30, 2022, the Company recorded net income attributable to shareholders of $80 million compared to net income attributable to shareholders of $20 million for the quarter ended June 30, 2021. Increases in net income were due to: higher adjusted EBITDA from our Alberta commercial facilities mainly attributable to the higher generation and realized power pricing on our Alberta commercial facilities, more frequent dispatch and higher availability from our U.S. contracted thermal facilities and strong wind resources experienced at our U.S. wind facilities. Lower net finance expense in the second quarter of 2022 was largely due to lower interest on decreased loans and borrowings, higher capitalized interest from the continued advancement of the Genesee repowering project and higher unrealized gains on non-hedge interest rate swaps driven by larger impacts of increasing market interest rates in the second quarter of 2022 compared to 2021. These increases were partially offset by higher depreciation expense due to phases 2 and 3 of Whitla Wind (commenced commercial operations in December 2021), Strathmore Solar (commenced commercial operations in March 2022, see Significant Events) and further shortened useful life of the Genesee Mine, partially offset by the classification of Island Generation EPA as a finance lease during the second quarter of 2022 (see Significant Events). Further decreases to net income were due to higher unrealized foreign exchange losses from the revaluation of U.S. dollar denominated debt and higher income tax expense primarily due to higher consolidated net income before tax in the second quarter of 2022 coupled with a $10 million deferred income tax benefit in the prior period that was attributable to lower applicable jurisdictional tax rates, of which there is no comparable tax recovery recognized in 2022.

For the quarter ended March 31, 2022, the Company recorded net income attributable to shareholders of $122 million compared to net income attributable to shareholders of $103 million for the quarter ended March 31, 2021. Increases in net income were due largely to higher adjusted EBITDA from: our Alberta commercial facilities due to higher generation and higher realized Alberta power prices, higher dispatch at Goreway and wind resource availability at Port Dover and Nanticoke Wind and the commissioning of phases 2 and 3 of Whitla Wind in December

2021. Net finance expense was lower for the quarter ended March 31, 2022 largely due to lower interest on decreased loans and borrowings outstanding. Unrealized losses on commodity derivatives and emission credits were $11 million higher in the first quarter of 2022 due to the impact of increasing forward power prices on Alberta and U.S. net forward sale contracts partially offset by the impact of increasing forward natural gas prices on net forward purchase contracts. Further decreases to net income during the quarter were due to: lower adjusted EBITDA from U.S contracted facilities primarily driven by the impacts of the extreme weather event at Buckthorn Wind in February 2021; higher depreciation expense due to commencement of commercial operations of phases 2 and 3 of Whitla Wind; and higher income tax expense primarily due to higher consolidated net income before tax in the first quarter of 2022.

For the quarter ended December 31, 2021, the Company recorded net loss attributable to shareholders of $65 million compared to net income attributable to shareholders of $3 million for the quarter ended December 31, 2020. Decreases in net income were driven by an impairment loss of $52 million related to the Island Generation facility in the fourth quarter of 2021 compared to the impairment recorded in the fourth quarter of 2020 related to the cancellation of the Genesee 1 and 2 dual-fuel project. Unrealized losses on commodity derivatives and emission credits in the fourth quarter of 2021 were $104 million higher than in the fourth quarter of 2020, most notably related to the impact of increasing forward power prices on Alberta and U.S. net forward sale contracts and the impact of decreasing forward natural gas prices on net forward purchase contracts during the fourth quarter of 2021. In addition, net income was reduced compared to the fourth quarter of 2020 by lower adjusted EBITDA from our U.S. contracted facilities, including the impact of the retirement of the Southport and Roxboro facilities, and higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine. Partially offsetting these operational variances were higher Alberta commercial adjusted EBITDA due largely to higher captured prices and the impacts of the Genesee 1 and 2 PPA expiry, and lower net finance expense.

For the quarter ended September 30, 2021, the Company recorded net income attributable to shareholders of $40 million compared to net income attributable to shareholders of $108 million for the quarter ended September 30, 2020. Decreases in net income were due to: lower adjusted EBITDA from U.S. contracted facilities, including the impact of the retirement of the Southport and Roxboro facilities effective March 31, 2021, unrealized losses on commodity derivatives and emission credits that were $97 million higher than the unrealized gains in the third quarter of 2020 mainly due to the impact of increasing forward prices on Alberta and U.S. power net forward sale contracts, partially offset by the impact of increasing forward prices on natural gas net forward purchase contracts; and higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine. These decreases were partially offset by $31 million of gains on disposals and other transactions including insurance recoveries, net of related expenses to repair Genesee 2 and a gain on decommissioning of the Southport and Roxboro facilities to reflect lower than expected decommissioning costs. Lastly, income tax expense was lower in the third quarter of 2021 primarily due to lower consolidated income before tax.

For the quarter ended June 30, 2021, the Company recorded net income attributable to shareholders of $20 million compared to net income attributable to shareholders of $23 million for the quarter ended June 30, 2020. Decreases in net income were due to: lower adjusted EBITDA from U.S. contracted facilities primarily due to the retirement of the Southport and Roxboro facilities effective March 31, 2021 and the impacts of the strengthening Canadian dollar; unrealized losses on commodity derivatives and emission credits that were $15 million higher than in the second quarter of 2020 mainly due to the impact of increasing forward prices on U.S. power forward sale contracts, partially offset by unrealized gains on natural gas net forward purchase contracts; higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine; and unrealized foreign exchange losses on outstanding foreign currency non-hedge sale contracts transacted during the second quarter of 2021. These decreases were largely offset by higher adjusted EBITDA from Alberta commercial facilities due to higher realized Alberta power prices and the dispatch of Genesee 1 and 2 being on a merchant basis and the accelerated recognition of off-coal compensation.

For the quarter ended March 31, 2021, the Company recorded net income attributable to shareholders of $103 million compared to net income attributable to shareholders of $2 million for the quarter ended March 31, 2020. Increases in net income were due largely to higher adjusted EBITDA from: Alberta commercial facilities due to higher realized Alberta power prices and the dispatch of Genesee 1 and 2 being on a merchant basis, the accelerated recognition of off-coal compensation, the acquisition of Buckthorn Wind in the second quarter of 2020 and the commissioning of Cardinal Point Wind late in the first quarter of 2020. Unrealized losses on commodity derivatives and emission credits were $11 million lower than in the first quarter of 2020 mainly due to the impact of increasing forward prices resulting in unrealized gains on commodity forward purchase contracts, partially offset by unrealized losses on U.S. power forward sale contracts. Further increases in net income during the quarter were due to: an unrealized foreign exchange gain resulting from the strengthening of the Canadian dollar on foreign currency sale contracts compared to a loss in the first quarter of 2020; gains on the interest rate non-hedge held within the York Energy joint venture due to increasing interest rates compared with losses in the first quarter of 2020; and reductions in impairment losses compared to the first quarter of 2020 related to the discontinuation of the Genesee 4 and 5 project. Partially offsetting these variances were higher emissions costs at Genesee, higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine, and the commissioning of Cardinal Point Wind and acquisition of Buckthorn Wind.

For the quarter ended December 31, 2020, the Company recorded net income attributable to shareholders of $3 million compared to net income attributable to shareholders of $182 million for the quarter ended December 31, 2019. Decreases in net income were notably driven by accelerated off-coal compensation recognition and the gain recognized in 2019 as a result of the swap of interests in Genesee 3 and Keephills 3 during the fourth quarter of 2019. Also contributing to reduced net income was the impairment recorded in the fourth quarter of 2020 related to the cancellation of the Genesee 1 and 2 dual-fuel project. Unrealized losses on commodity derivatives and emission credits in the fourth quarter 2020 were $19 million compared with unrealized gains of $28 million in the comparable 2019 period, most notably related to the impact of decreasing forward natural gas prices on net forward purchase contracts during the fourth quarter of 2020. In addition, net income was reduced compared to the fourth quarter of 2019 driven by various operational variances including lower Alberta commercial adjusted EBITDA due largely to higher emission costs upon changes to the Company's emission compliance strategy in the fourth quarter of 2020 and lower margins earned on natural gas portfolio optimization activities. Arlington Valley also realized lower adjusted EBITDA driven by the revised tolling agreement in effect for 2020. Partially offsetting these operational variances was higher adjusted EBITDA from the acquisition of Buckthorn Wind in the second quarter of 2020 and commencement of operations of phase 1 of Whitla Wind late in the fourth quarter of 2019 and Cardinal Point Wind late in the first quarter of 2020. Net finance expense also increased compared to 2019 as a result of these asset additions. Income tax expense was lower in 2020, driven by the tax effect of the noted variances, primarily the accelerated recognition of deferred government grant revenue upon close of the Genesee 3 and Keephills 3 swap transaction.

## SHARE AND PARTNERSHIP UNIT INFORMATION

### Quarterly common share trading information

The Company's common shares are listed on the Toronto Stock Exchange under the symbol CPX and began trading on June 26, 2009.

| | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Sep 2022 | Jun 2022 | Mar 2022 | Dec 2021 | Sep 2021 | Jun 2021 | Mar 2021 | Dec 2020 |
| **Share price ($/common share)** | | | | | | | | |
| High | 51.90 | 46.51 | 41.98 | 45.05 | 45.04 | 42.28 | 38.34 | 36.47 |
| Low | 44.34 | 40.48 | 36.35 | 37.95 | 39.99 | 36.22 | 33.31 | 29.13 |
| Close | 46.90 | 45.01 | 40.71 | 39.46 | 42.71 | 40.95 | 36.40 | 34.98 |
| **Volume of shares traded (millions)** | 28.2 | 19.9 | 21.6 | 15.8 | 13.4 | 21.3 | 22.9 | 20.2 |

### Outstanding share and partnership unit data

At October 26, 2022, the Company had 116.860 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 11) and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares at October 26, 2022 were 118.597 million. The outstanding special limited voting share is held by EPCOR.

Capital Power issued 350,000 Series 2022-A Class A Preferred Shares to the Computershare Trust Company of Canada, to be held in trust (see Significant Events).

At October 26, 2022, CPLP had 198.113 million general partnership units outstanding and 737.362 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

## ADDITIONAL INFORMATION

Additional information relating to Capital Power Corporation, including the Company's annual information form and other continuous disclosure documents, is available on SEDAR at www.sedar.com.

Condensed Interim Consolidated Financial Statements of

# CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)
Nine months ended September 30, 2022 and 2021

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2022 and 2021

**Condensed Interim Consolidated Financial Statements:**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# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Income
(Unaudited, in millions of Canadian dollars, except per share amounts)

| | Three months ended September 30, 2022 | Three months ended September 30, 2021 | Nine months ended September 30, 2022 | Nine months ended September 30, 2021 |
|---|---|---|---|---|
| Revenues | $ 735 | $ 325 | $ 1,838 | $ 1,153 |
| Other income | 51 | 52 | 162 | 165 |
| Energy purchases and fuel | (419) | (58) | (806) | (274) |
| **Gross margin** | 367 | 319 | 1,194 | 1,044 |
| Other raw materials and operating charges | (36) | (32) | (109) | (114) |
| Staff costs and employee benefits expense | (48) | (44) | (134) | (135) |
| Depreciation and amortization | (133) | (133) | (414) | (402) |
| Impairments, net of reversal | - | (8) | - | (6) |
| Other administrative expense | (40) | (28) | (101) | (79) |
| Foreign exchange loss | (12) | (7) | (18) | (8) |
| **Operating income** | 98 | 67 | 418 | 300 |
| (Losses) and gains on disposals and other transactions | (3) | 31 | (4) | 30 |
| Net finance expense | (40) | (43) | (112) | (130) |
| Income from joint ventures | - | 1 | 13 | 8 |
| **Income before tax** | 55 | 56 | 315 | 208 |
| Income tax expense (note 4) | (24) | (18) | (88) | (52) |
| **Net income** | $ 31 | $ 38 | $ 227 | $ 156 |
| **Attributable to:** | | | | |
| Non-controlling interests | $ (3) | $ (2) | $ (9) | $ (7) |
| Shareholders of the Company | $ 34 | $ 40 | $ 236 | $ 163 |
| **Earnings per share** (attributable to common shareholders of the Company): | | | | |
| Basic (note 5) | $ 0.21 | $ 0.23 | $ 1.76 | $ 1.10 |
| Diluted (note 5) | $ 0.20 | $ 0.23 | $ 1.75 | $ 1.09 |

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Comprehensive Income
(Unaudited, in millions of Canadian dollars)

| | Three months ended September 30, 2022 | Three months ended September 30, 2021 | Nine months ended September 30, 2022 | Nine months ended September 30, 2021 |
|---|---|---|---|---|
| **Net income** | $ 31 | $ 38 | $ 227 | $ 156 |
| **Other comprehensive income (loss):** | | | | |
| **Items that will not be reclassified subsequently to net income:** | | | | |
| Defined benefit plans: | | | | |
| Actuarial gains[1] | - | - | 10 | - |
| **Items that are or may be reclassified subsequently to net income:** | | | | |
| Cash flow hedges: | | | | |
| Unrealized losses on derivative instruments[2] | (222) | (60) | (224) | (166) |
| Reclassification of losses on derivative instruments to income for the period[3] | 165 | 39 | 217 | 125 |
| Net investment in foreign subsidiaries: | | | | |
| Unrealized gains[4] | 73 | 28 | 96 | 10 |
| Total items that are or may be reclassified subsequently to net income, net of tax | 16 | 7 | 89 | (31) |
| Total other comprehensive income (loss), net of tax | 16 | 7 | 99 | (31) |
| **Total comprehensive income** | $ 47 | $ 45 | $ 326 | $ 125 |
| **Attributable to:** | | | | |
| Non-controlling interests | $ (3) | $ (2) | $ (9) | $ (7) |
| Shareholders of the Company | $ 50 | $ 47 | $ 335 | $ 132 |

[1] For the three and nine months ended September 30, 2022, net of income tax expense of nil and $3. For the three and nine months ended September 30, 2021, net of income tax expense of nil.

[2] For the three and nine months ended September 30, 2022, net of income tax recoveries of $68. For the three and nine months ended September 30, 2021, net of income tax recoveries of $20 and $53, respectively.

[3] For the three and nine months ended September 30, 2022, net of reclassification of income tax recoveries of $50 and $66, respectively. For the three and nine months ended September 30, 2021, net of reclassification of income tax recoveries of $12 and $39, respectively.

[4] For the three and nine months ended September 30, 2022 and 2021, net of income tax expense of nil.

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Financial Position
(Unaudited, in millions of Canadian dollars)

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ 211 | $ 387 |
| Trade and other receivables | 757 | 474 |
| Inventories | 209 | 217 |
| Derivative financial instruments assets (note 6) | 172 | 108 |
| | 1,349 | 1,186 |
| Non-current assets: | | |
| Other assets | 47 | 47 |
| Derivative financial instruments assets (note 6) | 337 | 222 |
| Finance lease receivable (note 7) | 36 | - |
| Government grant receivable | 307 | 349 |
| Deferred tax assets | 16 | 17 |
| Equity-accounted investments (note 3) | 433 | 145 |
| Right-of-use assets | 122 | 120 |
| Intangible assets and goodwill | 779 | 784 |
| Property, plant and equipment | 6,330 | 6,203 |
| Total assets | $ 9,756 | $ 9,073 |
| Liabilities and equity | | |
| Current liabilities: | | |
| Trade and other payables | $ 1,018 | $ 624 |
| Derivative financial instruments liabilities (note 6) | 434 | 252 |
| Loans and borrowings (note 8) | 130 | 126 |
| Deferred revenue and other liabilities | 147 | 153 |
| Provisions | 51 | 50 |
| | 1,780 | 1,205 |
| Non-current liabilities: | | |
| Derivative financial instruments liabilities (note 6) | 482 | 352 |
| Loans and borrowings (note 8) | 3,294 | 3,234 |
| Lease liabilities | 142 | 137 |
| Deferred revenue and other liabilities | 279 | 291 |
| Deferred tax liabilities | 634 | 584 |
| Provisions | 321 | 411 |
| | 5,152 | 5,009 |
| Equity: | | |
| Equity attributable to shareholders of the Company | | |
| Share capital (note 9) | 3,497 | 3,631 |
| Deficit | (661) | (671) |
| Other reserves | (20) | (119) |
| Deficit and other reserves | (681) | (790) |
| | 2,816 | 2,841 |
| Non-controlling interests | 8 | 18 |
| Total equity | 2,824 | 2,859 |
| Total liabilities and equity | $ 9,756 | $ 9,073 |

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

| | Share capital (note 9) | Cash flow hedges[1] | Cumulative translation reserve[1] | Defined benefit plan actuarial losses[1] | Employee benefits reserve | Deficit | Equity attributable to shareholders of the Company | Non-controlling interests | Total |
|---|---|---|---|---|---|---|---|---|---|
| Equity as at January 1, 2022 | $ 3,631 | $ (84) | $ (28) | $ (17) | $ 10 | $ (671) | $ 2,841 | $ 18 | $ 2,859 |
| Net income | - | - | - | - | - | 236 | 236 | (9) | 227 |
| Other comprehensive (loss) income: | | | | | | | | | |
| Defined benefit plan actuarial gain | - | - | - | 13 | - | - | 13 | - | 13 |
| Cash flow derivative hedge losses | - | (292) | - | - | - | - | (292) | - | (292) |
| Reclassification of derivative hedge losses to net income | - | 283 | - | - | - | - | 283 | - | 283 |
| Unrealized gains on foreign currency translation | - | - | 96 | - | - | - | 96 | - | 96 |
| Tax on items recognized directly in equity | - | 2 | - | (3) | - | - | (1) | - | (1) |
| Other comprehensive (loss) income | $ - | $ (7) | $ 96 | $ 10 | $ - | $ - | $ 99 | $ - | $ 99 |
| Total comprehensive (loss) income | - | (7) | 96 | 10 | - | 236 | 335 | (9) | 326 |
| Distributions to non-controlling interests | - | - | - | - | - | - | - | (1) | (1) |
| Common share dividends (note 9) | - | - | - | - | - | (195) | (195) | - | (195) |
| Preferred share dividends (note 9) | - | - | - | - | - | (29) | (29) | - | (29) |
| Tax on preferred share dividends | - | - | - | - | - | (2) | (2) | - | (2) |
| Preferred share redemption (note 9) | (150) | - | - | - | - | - | (150) | - | (150) |
| Share-based payments | - | - | - | - | 1 | - | 1 | - | 1 |
| Share options exercised | 16 | - | - | - | (1) | - | 15 | - | 15 |
| Equity as at September 30, 2022 | $ 3,497 | $ (91) | $ 68 | $ (7) | $ 10 | $ (661) | $ 2,816 | $ 8 | $ 2,824 |

[1] Accumulated other comprehensive loss. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive loss and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

| | Share capital (note 9) | Cash flow hedges[1] | Cumulative translation reserve[1] | Defined benefit plan actuarial losses[1] | Employee benefits reserve | Deficit | Equity attributable to shareholders of the Company | Non-controlling interests | Total |
|---|---|---|---|---|---|---|---|---|---|
| Equity as at January 1, 2021 | $ 3,465 | $ (48) | $ (34) | $ (20) | $ 11 | $ (474) | $ 2,900 | $ 29 | $ 2,929 |
| Net income | - | - | - | - | - | 163 | 163 | (7) | 156 |
| Other comprehensive (loss) income: | | | | | | | | | |
| Cash flow derivative hedge losses | - | (219) | - | - | - | - | (219) | - | (219) |
| Reclassification of derivative hedge losses to net income | - | 164 | - | - | - | - | 164 | - | 164 |
| Unrealized gains on foreign currency translation | - | - | 10 | - | - | - | 10 | - | 10 |
| Tax on items recognized directly in equity | - | 14 | - | - | - | - | 14 | - | 14 |
| Other comprehensive loss (income) | $ - | $ (41) | $ 10 | $ - | $ - | $ - | $ (31) | $ - | $ (31) |
| Total comprehensive (loss) income | - | (41) | 10 | - | - | 163 | 132 | (7) | 125 |
| Common share dividends (note 9) | - | - | - | - | - | (177) | (177) | - | (177) |
| Preferred share dividends (note 9) | - | - | - | - | - | (38) | (38) | - | (38) |
| Tax on preferred share dividends | - | - | - | - | - | (3) | (3) | - | (3) |
| Issue of share capital | 288 | - | - | - | - | - | 288 | - | 288 |
| Share issue costs | (12) | - | - | - | - | - | (12) | - | (12) |
| Deferred tax on share issue costs | 3 | - | - | - | - | - | 3 | - | 3 |
| Dividends reinvested | 47 | - | - | - | - | - | 47 | - | 47 |
| Share-based payments | - | - | - | - | 1 | - | 1 | - | 1 |
| Share options exercised | 21 | - | - | - | (2) | - | 19 | - | 19 |
| Equity as at September 30, 2021 | $ 3,812 | $ (89) | $ (24) | $ (20) | $ 10 | $ (529) | $ 3,160 | $ 22 | $ 3,182 |

[1] Accumulated other comprehensive loss. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive loss and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Cash Flows
(Unaudited, in millions of Canadian dollars)

| | Nine months ended September 30, 2022 | 2021 |
|---|---|---|
| **Cash flows from operating activities:** | | |
| Net income | $ 227 | $ 156 |
| Non-cash adjustments to reconcile net income to net cash flows from operating activities: | | |
| Impairments, net of reversal | - | 6 |
| Depreciation and amortization | 414 | 402 |
| Net finance expense | 112 | 130 |
| Fair value changes on commodity derivative instruments and emission credits held for trading | 182 | 97 |
| Foreign exchange losses | 18 | 8 |
| Income tax expense | 88 | 52 |
| Income from joint ventures | (13) | (8) |
| Recognition of government grant deferred revenue | (94) | (94) |
| Tax equity attributes | (61) | (66) |
| Other items | 29 | 8 |
| Change in fair value of derivative instruments reflected as cash settlement | (60) | (17) |
| Distributions received from joint ventures | 6 | 8 |
| Interest paid | (76) | (98) |
| Income taxes (paid) recovered | (24) | 13 |
| Other cash items | (6) | (20) |
| Change in non-cash operating working capital | 151 | 105 |
| Net cash flows from operating activities | 893 | 682 |
| **Cash flows used in investing activities:** | | |
| Purchase of property, plant and equipment and other assets, net[1] | (503) | (424) |
| Acquisition of equity-accounted investment (note 3) | (273) | - |
| Government grant received | 50 | 50 |
| Other cash flows from investing activities | - | 7 |
| Net cash flows used in investing activities | (726) | (367) |
| **Cash flows used in financing activities:** | | |
| Proceeds from issue of loans and borrowings (note 8) | 350 | - |
| Repayment of loans and borrowings | (298) | (518) |
| Issue costs on loans and borrowings | (4) | (1) |
| Repayment of lease liabilities | (4) | (4) |
| Issue of shares | - | 288 |
| Share issue costs | - | (12) |
| Proceeds from exercise of share options | 15 | 19 |
| Redemption of preferred shares (note 9) | (150) | - |
| Dividends paid (note 9) | (220) | (159) |
| Capitalized interest paid | (13) | (6) |
| Distributions to non-controlling interests | (1) | - |
| Income taxes paid on preferred share dividends | (12) | (4) |
| Net cash flows used in financing activities | (337) | (397) |
| Foreign exchange loss on cash held in foreign currency | (6) | - |
| Net decrease in cash and cash equivalents | (176) | (82) |
| Cash and cash equivalents at beginning of period | 387 | 367 |
| Cash and cash equivalents at end of period | $ 211 | $ 285 |

[1] Reflects total additions for the nine months ended September 30, 2022, reduced by $48 million for changes in non-cash investing working capital and other non-current liabilities (nine months ended September 30, 2021 – reduced by $137 million), to arrive at cash additions of property, plant and equipment and other assets.

See accompanying notes to the condensed interim consolidated financial statements

**1. Reporting entity:**

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns and operates utility-scale renewable and thermal power generation facilities and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

The registered and head office of the Company is located at 10423 101 Street, Edmonton, Alberta, Canada, T5H 0E9. The common shares of the Company are traded on the Toronto Stock Exchange under the symbol “CPX”.

Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim results are not necessarily indicative of annual results.

**2. Basis of presentation:**

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s 2021 annual consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS).

These condensed interim consolidated financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent annual consolidated financial statements and have been prepared under the historical cost basis, except for the Company’s derivative instruments, emission credits held for trading, defined benefit pension assets and cash-settled share-based payments, which are stated at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 28, 2022.

**3. Acquisition of Midland Cogeneration Venture**

On September 23, 2022, Capital Power and Manulife Investment Management, on behalf of the Manulife Infrastructure Fund II and its affiliates, each acquired 50% interest in MCV Holding Company LLC through its joint venture partnership, MCV Partners LLC. MCV Holding Company LLC owns 100% of Midland Cogeneration Venture Limited Partnership (Midland Cogen), a 1,633 MW natural gas combined-cycle cogeneration facility located in Michigan, USA.

The Company has assessed MCV Partners LLC as a joint venture as all relevant operating, investing and financing activities of MCV Partners LLC are shared jointly between Capital Power and its joint venture partner. Accordingly, Capital Power’s investment in MCV Partners LLC is accounted for under the equity method.

Capital Power’s investment for its 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). The Company previously entered into foreign exchange cash flow hedges of US$150 million pertaining to the hedged portion of U.S. dollar denominated funds used to acquire the equity-accounted investment. The hedges settled during the third quarter of 2022 for a gain of $7 million, which was realized within the equity accounted investment balance on the consolidated statements of financial position. The Company expects to finalize the working capital adjustment in the fourth quarter of 2022. Capital Power is responsible for operations and maintenance and asset management for which it will receive an annual management fee.

Due to the proximity of the acquisition’s closing date to September 30, 2022, the equity income from MCV Partners LLC was not material in the quarter.

Substantially all of the underlying assets and liabilities of Midland Cogen relate to the cogeneration facility and the project level debt.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

## 4. Income tax:

Income tax differs from the amount that would be computed by applying the federal and provincial income tax rates as follows:

| | Three months ended September 30, 2022 | Three months ended September 30, 2021 | Nine months ended September 30, 2022 | Nine months ended September 30, 2021 |
|---|---|---|---|---|
| Income before tax | $ 55 | $ 56 | $ 315 | $ 208 |
| Income tax at the statutory rate of 23% | 12 | 13 | 72 | 48 |
| Increase (decrease) resulting from: | | | | |
| Non-deductible amounts | 6 | 2 | 9 | 6 |
| Amounts attributable to non-controlling interests and tax-equity interests | 3 | 9 | 4 | 17 |
| Change in unrecognized tax benefits | 3 | (4) | 4 | (4) |
| Statutory and other rate differences | - | (3) | (1) | (17) |
| Other | - | 1 | - | 2 |
| Income tax expense | $ 24 | $ 18 | $ 88 | $ 52 |

## 5. Earnings per share:

The earnings and weighted average number of common shares used in the calculation of basic and diluted earnings per share are as follows:

| | Three months ended September 30, 2022 | Three months ended September 30, 2021 | Nine months ended September 30, 2022 | Nine months ended September 30, 2021 |
|---|---|---|---|---|
| Income for the period attributable to shareholders | $ 34 | $ 40 | $ 236 | $ 163 |
| Preferred share dividends[1] | (10) | (13) | (31) | (41) |
| Earnings available to common shareholders | $ 24 | $ 27 | $ 205 | $ 122 |
| Weighted average number of common shares | 116,658,263 | 115,492,560 | 116,427,899 | 110,712,898 |
| Basic earnings per share | $ 0.21 | $ 0.23 | $ 1.76 | $ 1.10 |
| Weighted average number of common shares | 116,658,263 | 115,492,560 | 116,427,899 | 110,712,898 |
| Effect of dilutive share purchase options | 761,710 | 832,799 | 726,046 | 761,455 |
| Diluted weighted average number of common shares | 117,419,973 | 116,325,359 | 117,153,945 | 111,474,353 |
| Diluted earnings per share | $ 0.20 | $ 0.23 | $ 1.75 | $ 1.09 |

[1] Includes preferred share dividends declared and related taxes.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

**6. Derivative financial instruments and hedge accounting:**

Derivative financial and non-financial instruments are held for the purposes of energy purchases, merchant trading or financial risk management.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

| | September 30, 2022 | | | | |
|---|---|---|---|---|---|
| | Energy and emission allowances | | Interest rate | | |
| | cash flow hedges | non-hedges | cash flow hedges | non-hedges | Total |
| Derivative instruments assets: | | | | | |
| Current | $ 13 | $ 149 | $ 2 | $ 8 | $ 172 |
| Non-current | 4 | 282 | 45 | 6 | 337 |
| Derivative instruments liabilities: | | | | | |
| Current | (139) | (290) | (5) | - | (434) |
| Non-current | (21) | (446) | (15) | - | (482) |
| Net fair value | $ (143) | $ (305) | $ 27 | $ 14 | $ (407) |
| Net notional buys (sells) (millions): | | | | | |
| Megawatt hours of electricity | (7) | (30) | | | |
| Gigajoules of natural gas purchased[1] | | 71 | | | |
| Gigajoules of natural gas basis swaps[1] | | 74 | | | |
| Metric tonnes of emission allowances | | 4 | | | |
| Number of renewable energy credits | | (11) | | | |
| Interest rate swaps | | | $ 1,191 | $ 230 | |
| Range of remaining contract terms in years | 0.1 to 4.3 | 0.1 to 24.4 | 1.7 to 4.3 | 0.7 to 1.2 | |

[1] The Company's natural gas trading strategy employs future purchase derivative instruments as well as basis swaps pertaining to certain of the future purchase derivative instruments, to manage its exposure to commodity price risk.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

**6. Derivative financial instruments and hedge accounting, continued:**

| | December 31, 2021 | | | | |
|---|---|---|---|---|---|
| | Energy and emission allowances | | Interest rate | | |
| | cash flow hedges | non-hedges | cash flow hedges | non-hedges | Total |
| Derivative instruments assets: | | | | | |
| Current | $ 5 | $ 94 | $ - | $ 9 | $ 108 |
| Non-current | 2 | 210 | 10 | - | 222 |
| Derivative instruments liabilities: | | | | | |
| Current | (72) | (149) | (31) | - | (252) |
| Non-current | (21) | (290) | (40) | (1) | (352) |
| Net fair value | $ (86) | $ (135) | $ (61) | $ 8 | $ (274) |
| Net notional buys (sells) (millions): | | | | | |
| Megawatt hours of electricity | (5) | (26) | | | |
| Gigajoules of natural gas purchased[2] | | 129 | | | |
| Gigajoules of natural gas basis swaps[2] | | 128 | | | |
| Number of renewable energy credits | | (8) | | | |
| Interest rate swaps | | | $ 1,501 | $ 80 | |
| Range of remaining contract terms in years | 0.1 to 4.0 | 0.1 to 25.1 | 0.7 to 5.1 | 1.4 to 1.9 | |

[2] The Company's natural gas trading strategy employs future purchase derivative instruments as well as basis swaps pertaining to certain of the future purchase derivative instruments, to manage its exposure to commodity price risk.

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2021 annual consolidated financial statements. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Unrealized and realized pre-tax gains and (losses) on derivative instruments recognized in other comprehensive income and net income are:

| | Three months ended September 30, 2022 | | Three months ended September 30, 2021 | |
|---|---|---|---|---|
| | Unrealized (losses) gains | Realized (losses) gains | Unrealized (losses) gains | Realized (losses) gains |
| Energy cash flow hedges | $ (59) | $ (216) | $ (41) | $ (49) |
| Energy and emission allowances non-hedges | (130) | (80) | (68) | 3 |
| Interest rate cash flow hedges[3] | (15) | 1 | 5 | (2) |
| Interest rate non-hedges[3] | (8) | 9 | 1 | - |
| Foreign exchange cash flow hedges | (1) | - | 7 | - |
| Foreign exchange non-hedges | - | - | (3) | (4) |

[3] Includes the settlement of interest rate cash flow hedges of US$335 million in August 2022 for accumulated gains of $35 million of which $27 million was deferred within accumulated other comprehensive income to be reclassified to net income in future periods within the associated net finance expense pertaining to the hedged note offering. The remaining gain of $8 million was previously recognized directly in net finance expense as it relates to the period prior to hedge designation.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

**6. Derivative financial instruments and hedge accounting, continued:**

| | Nine months ended September 30, 2022 | | Nine months ended September 30, 2021 | |
|---|---|---|---|---|
| | Unrealized (losses) gains | Realized (losses) gains | Unrealized (losses) gains | Realized (losses) gains |
| Energy cash flow hedges | $ (112) | $ (281) | $ (94) | $ (160) |
| Energy and emission allowances non-hedges | (171) | (127) | (100) | (5) |
| Interest rate cash flow hedges[4] | 103 | (2) | 27 | (4) |
| Interest rate non-hedges[4] | 6 | 9 | 10 | - |
| Foreign exchange cash flow hedges | - | - | 12 | - |
| Foreign exchange non-hedges | - | (1) | (9) | 1 |

[4] Includes the settlement of interest rate cash flow hedges of US$335 million in August 2022 for a gain of $35 million of which $27 million was deferred within accumulated other comprehensive income to be reclassified to net income in future periods within the associated net finance expense pertaining to the hedged note offering. The remaining gain of $8 million was previously recognized directly in net finance expense as it relates to the period prior to hedge designation (2021 - US$180 million settlement in June 2021 for a gain of $14 million of which $12 million was deferred within accumulated other comprehensive income).

The following realized and unrealized gains and (losses) are included in the Company's consolidated statements of income for the three and nine months ended September 30, 2022 and 2021:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2022 | 2021 | 2022 | 2021 |
| Revenues | $ (573) | $ (305) | $(1,070) | $ (739) |
| Energy purchases and fuel | 147 | 191 | 491 | 474 |
| Foreign exchange loss | - | (7) | (1) | (8) |
| Net finance expense | 2 | (1) | 13 | 6 |

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices, interest rate risk relating to future borrowings and foreign exchange risk relating to future capital investment in U.S. dollars. For the three and nine months ended September 30, 2022, the amount realized within net finance expense pertaining to the ineffective portion of hedging derivatives was nil (three and nine months ended September 30, 2021 – nil and $2 million of gains, respectively).

Net after tax gains and (losses) related to derivative instruments designated as energy and interest rate cash flow hedges are expected to settle and be reclassified to net income in the following periods:

| | September 30, 2022 |
|---|---|
| Within one year | $ (154) |
| Between one and five years | 25 |
| After five years | 30 |
| | $ (99) |

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

## 7. Finance lease receivable

In May 2022, Capital Power executed a 4.5-year energy purchase agreement (EPA) for its Island Generation facility with BC Hydro, effective May 2022 through to October 2026. The new EPA is classified as a finance lease, whereas the previous EPA which expired in April 2022 was classified as an operating lease. Accordingly, during the second quarter of 2022, Capital Power derecognized Island Generation's net assets that were previously presented within property, plant and equipment on the consolidated statements of financial position and recognized a corresponding finance lease receivable, with the current portion included within trade and other receivables. The new EPA is subject to regulatory approval by the British Columbia Utilities Commission.

Finance income of $4 million and $6 million was recognized in revenues for the three and the nine months ended September 30, 2022, respectively.

The following table sets out the maturity analysis of the lease receivable, showing the minimum undiscounted lease payments to be received:

| | September 30, 2022 |
|---|---|
| Amounts receivable under finance lease: | |
| Less than one year | $ 19 |
| Between one and five years | 45 |
| Total undiscounted lease receivable | 64 |
| Unearned finance income | (22) |
| Net investment in lease | 42 |
| Less: current portion[1] | (6) |
| | $ 36 |

[1] Included within trade and other receivables

## 8. $350 million Green Hybrid Subordinated Notes offering

On September 9, 2022, the Company closed a $350 million, net of $3 million issuance costs, offering of Fixed-to-Fixed Subordinated Notes, Series 1, due September 9, 2082. The Series 1 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.

The Series 1 Subordinated Notes are subject to optional redemption by the Company from June 9, 2032 to September 9, 2032 and on any interest payment date or any interest reset date, as applicable. The Company may also redeem the Series 1 Subordinated Notes in certain other circumstances. Following the occurrence of certain bankruptcy or insolvency events in respect of the Company, subject to certain exceptions, the Series 2022-A Class A Preferred Shares (as defined below) will be delivered to the holders of the Series 1 Subordinated Notes to satisfy the Company's obligations under the indenture governing the Series 1 Subordinated Notes. Upon delivery of the Series 2022-A Class A Preferred Shares, the Series 1 Subordinated Notes will be immediately and automatically surrendered and cancelled and all rights of any holders of the Series 1 Subordinated Notes will automatically cease. The fair value of Series 2022-A Class A Preferred Shares was assessed as nominal at inception.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

## 9. Share capital:

| | Dividends declared | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | For the three months ended September 30, | | | | For the nine months ended September 30, | | | |
| | 2022 | | 2021 | | 2022 | | 2021 | |
| | Per share | Total | Per share | Total | Per share | Total | Per share | Total |
| Common | $ 0.5800 | $ 68 | $ 0.5475 | $ 63 | $ 1.6750 | $ 195 | $ 1.5725 | $177 |
| Preference[3] | | | | | | | | |
| Series 1 | 0.1638 | 1 | 0.1638 | 1 | 0.4914 | 3 | 0.4914 | 3 |
| Series 3 | 0.3408 | 2 | 0.3408 | 2 | 1.0224 | 6 | 1.0224 | 6 |
| Series 5 | 0.3274 | 2 | 0.3274 | 3 | 0.9821 | 8 | 0.9821 | 8 |
| Series 7[1] | - | - | 0.3750 | 3 | - | - | 1.1250 | 9 |
| Series 9[2] | 0.3594 | 2 | 0.3594 | 2 | 1.0781 | 6 | 1.0781 | 6 |
| Series 11 | 0.3594 | 2 | 0.3594 | 2 | 1.0781 | 6 | 1.0781 | 6 |

[1] On December 31, 2021, the Company redeemed all of its 8 million issued and outstanding 6.00% cumulative rate reset preference shares, Series 7.

[2] On September 30, 2022, the Company redeemed all of its 6 million issued and outstanding 5.75% cumulative rate reset preference shares, Series 9 at a price of $25.00 per share for an aggregate total of $150 million. The quarterly dividend for the third quarter of 2022 will be the final quarterly dividend on the Series 9 Shares and, as the redemption date is also the dividend payment date, the redemption price will not include the quarterly dividend for the third quarter of 2022. Instead, the quarterly dividend for the third quarter of 2022 was paid on the redemption date separately to shareholders of record as of September 19, 2022.

[3] On September 9, 2022, in connection with the Company's offering of the Series 1 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 indenture governing the Series 1 Subordinated Notes.

| | Dividends paid[4] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | For the three months ended September 30, | | | | For the nine months ended September 30, | | | |
| | 2022 | | 2021 | | 2022 | | 2021 | |
| | Per share | Total | Per share | Total | Per share | Total | Per share | Total |
| Common[5] | $ 0.5475 | $ 63 | $ 0.5125 | $ 59 | $ 1.6425 | $ 191 | $ 1.5375 | $168 |

[4] Preference Share dividends are declared and paid in the same period.

[5] For the three and nine months ended September 30, 2022, all common dividends were paid in cash.

For the three months ended September 30, 2021, dividends paid on common shares consist of $42 million paid in cash and $17 million paid through the Company's dividend reinvestment plan as common shares issued. For the nine months ended September 30, 2021, dividends paid on common shares consist of $121 million paid in cash and $47 million paid through the Company's dividend reinvestment plan as common shares issued.

During the three and nine months ended September 30, 2022 and 2021, the Company did not purchase and cancel any of its outstanding common shares under its Toronto Stock Exchange approved normal course issuer bid.

In March 2022, the Toronto Stock Exchange approved the Company's normal course issuer bid to purchase and cancel up to 8 million of its outstanding common shares during the one-year period from February 28, 2022 to February 27, 2023.

**Dividend increase**

On July 29, 2022, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $2.19 per common share to $2.32 per common share. This increased common share dividend will commence with the third quarter 2022 quarterly dividend payment on October 31, 2022 to shareholders of record at the close of business on September 30, 2022.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

## 10. Financial instruments

### Fair values

Details of the fair values of the Company's derivative instruments are described in note 6.

The Company's other short-term financial instruments are classified and measured at amortized cost, consistent with the methodologies described in the Company's 2021 annual consolidated financial statements. Due to the short-term nature of the financial instruments, the fair values are not materially different from their carrying amounts.

The fair values of the Company's other long-term financial instruments are determined using the same valuation techniques, inputs, and assumptions as described in the Company's 2021 annual consolidated financial statements. The carrying amount and fair value of the Company's other financial instruments, which are all classified and subsequently measured at amortized cost, are summarized as follows:

| | | September 30, 2022 | | December 31, 2021 | |
|---|---|---|---|---|---|
| | Fair value hierarchy level | Carrying amount | Fair value | Carrying amount | Fair value |
| Financial assets[1] | | | | | |
| Government grant receivable | Level 2 | $ 364 | $ 318 | $ 404 | $ 395 |
| Financial liabilities[1] | | | | | |
| Loans and borrowings | Level 2 | $ 3,424 | $ 3,277 | $ 3,360 | $ 3,515 |

[1] Includes current portion.

### Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statements of financial position are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The valuation techniques used by the Company in determining the fair value of its financial instruments are the same as those used at December 31, 2021.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2021 annual consolidated financial statements, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels.

The Company's policy is to recognize transfers between levels as of the date of the event or change in circumstances that caused the transfer. There were no transfers between levels in the fair value hierarchy for the nine months ended September 30, 2022 and the year ended December 31, 2021.

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in the Company's 2021 annual consolidated financial statements.

| | September 30, 2022 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Derivative financial instruments assets | $ - | $ 490 | $ 19 | $ 509 |
| Derivative financial instruments liabilities | - | (519) | (397) | (916) |

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

**10. Financial instruments, continued:**

**Fair value hierarchy, continued**

| | December 31, 2021 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Derivative financial instruments assets | $ - | $ 316 | $ 14 | $ 330 |
| Derivative financial instruments liabilities | - | (406) | (198) | (604) |

*Valuation techniques used in determination of fair values within Level 3*

The Company has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, their fair values are derived using forecasts based on internal modelling and as a result, are classified within Level 3 of the hierarchy.

The Company has a fixed price contract to swap the market revenue of its Bloom Wind generation for a fixed annual payment for a 10-year term that expires in 2027. Anticipated generation continues to be forecasted based on internal modelling. Accordingly, this financial instrument is classified as Level 3.

The Company has a 20-year revenue offtake swap agreement for Buckthorn Wind, expiring in 2038, where the market price is swapped for a fixed price per unit of actual generation. The notional quantities are not set forth in the contract and observable forward market pricing is only available for the next 12 years. As such, the Company has developed a generation forecast for the remainder of the contract and a price forecast for the 4 years for which forward market prices are not available. These are both significant inputs to the determination of fair value, therefore this financial instrument is classified as Level 3.

The Company has a 10-year renewable energy agreement for Whitla Wind, a 15-year fixed price contract for Enchant Solar and a 25-year fixed price contract for Strathmore Solar, expiring in 2032, 2037 and 2047, respectively, to generate renewable generation and deliver environmental attributes. Observable forward market prices are not available for the full terms of the contracts and notional quantities used to calculate fair value reflect anticipated generation, therefore pricing and generation forecasts have been developed based on internal modelling. Accordingly, these financial instruments are classified as Level 3.

In addition, at September 30, 2022 and December 31, 2021, the Company holds contracts for the sale of renewable energy credits for which pricing beyond two years is not readily observable and the contracts are therefore classified in Level 3 of the hierarchy.

The fair values of the Company’s commodity derivatives included within Level 3 are determined by applying a mark-to-forecast model. The table below presents ranges for the Company’s Level 3 inputs:

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| REC pricing (per certificate) – Solar | $2.75 to $328.18 | $2.96 to $352.48 |
| REC pricing (per certificate) – Wind | $2.09 to $4.60 | $2.07 to $4.18 |
| Forward power pricing (per MWh) – Solar | $38.09 to $192.00 | $35.32 to $113.86 |
| Forward power pricing (per MWh) – Wind | $26.66 to $156.52 | $25.25 to $88.42 |
| Average monthly generation (MWh) – Strathmore Solar | 7,090 | 7,123 |
| Average monthly generation (MWh) – Enchant Solar | 6,905 | 6,905 |
| Average monthly generation (MWh) – Whitla Wind | 41,673 | N/A |
| Average monthly generation (MWh) – Bloom Wind | 59,274 | 59,067 |
| Average monthly generation (MWh) – Buckthorn Wind | 17,711 | 17,702 |

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

### 10. Financial instruments, continued:

**Fair value hierarchy, continued**

*Valuation process applied to Level 3*

The valuation models used to calculate the fair values of the derivative financial instrument assets and liabilities within Level 3 are prepared by appropriate internal subject matter experts and reviewed by the Company's commodity risk group and by management. The valuation technique and the associated inputs are assessed on a regular basis for ongoing reasonability.

The table below presents the increase or decrease to fair value of Level 3 derivative instruments based on a 10% decrease or increase in the respective input:

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| REC pricing – Solar | $ (1) | $ - |
| REC pricing – Wind | 1 | 1 |
| Forward power pricing – Solar | 34 | 16 |
| Forward power pricing – Wind | 56 | 31 |
| Generation – Solar | 5 | 1 |
| Generation – Wind | 21 | 14 |

*Continuity of Level 3 balances*

The Company classifies financial instruments in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model used to determine fair value. In addition to these unobservable inputs, the valuation model for Level 3 instruments also relies on a number of inputs that are observable either directly or indirectly. Accordingly, the unrealized gains and losses shown below include changes in the fair value related to both observable and unobservable inputs. The following table summarizes the changes in the fair value of financial instruments classified in Level 3:

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| At January 1[2] | $ (184) | $ 35 |
| Unrealized and realized losses included in net income[3] | (195) | (211) |
| Settlements[4] | 25 | (6) |
| Foreign exchange losses | (24) | (2) |
| At end of period | $ (378) | $ (184) |
| Total unrealized and realized losses for the period included in net income[3] | $ (195) | $ (211) |

[2] The fair value of derivative instruments assets and liabilities are presented on a net basis.

[3] Recorded in revenues.

[4] Relates to settlement of financial derivative instruments.

All instruments classified as Level 3 are derivative type instruments. Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. As a result, unrealized gains and losses from Level 3 financial instruments are often offset by unrealized gains and losses on financial instruments that are classified in Levels 1 or 2.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

### 11. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation facilities within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina, New Mexico, Kansas, Alabama, Arizona, North Dakota, Illinois, Texas and Michigan), as this is how management assesses performance and determines resource allocations. The Company also holds a portfolio of wind and solar development sites in the U.S. and Canada.

The Company's results from operations within each geographic area are:

| | Three months ended September 30, 2022 | | | | Three months ended September 30, 2021 | | | |
|---|---|---|---|---|---|---|---|---|
| | Canada | U.S. | Inter-area eliminations | Total | Canada | U.S. | Inter-area eliminations | Total |
| Revenues – external[1] | $ 661 | $ 74 | $ - | $ 735 | $ 396 | $ (71) | $ - | $ 325 |
| Revenues – inter-area | (34) | 42 | (8) | - | 5 | - | (5) | - |
| Other income | 35 | 16 | - | 51 | 34 | 18 | - | 52 |
| Total revenues and other income | $ 662 | $ 132 | $ (8) | $ 786 | $ 435 | $ (53) | $ (5) | $ 377 |

| | Nine months ended September 30, 2022 | | | | Nine months ended September 30, 2021 | | | |
|---|---|---|---|---|---|---|---|---|
| | Canada | U.S. | Inter-area eliminations | Total | Canada | U.S. | Inter-area eliminations | Total |
| Revenues – external[1] | $ 1,810 | $ 28 | $ - | $ 1,838 | $ 1,240 | $ (87) | $ - | $1,153 |
| Revenues – inter-area | (99) | 119 | (20) | - | 18 | - | (18) | - |
| Other income | 101 | 61 | - | 162 | 100 | 65 | - | 165 |
| Total revenues and other income | $ 1,812 | $ 208 | $ (20) | $ 2,000 | $ 1,358 | $ (22) | $ (18) | $1,318 |

[1] Revenues from external sources includes realized and unrealized gains and losses from derivative financial instruments.

| | At September 30, 2022 | | | At December 31, 2021 | | |
|---|---|---|---|---|---|---|
| | Canada | U.S. | Total | Canada | U.S. | Total |
| Property, plant and equipment | $ 4,682 | $ 1,648 | $ 6,330 | $ 4,603 | $ 1,600 | $ 6,203 |
| Right-of-use assets | 56 | 66 | 122 | 56 | 64 | 120 |
| Intangible assets and goodwill | 643 | 136 | 779 | 645 | 139 | 784 |
| Finance lease receivable[2] (note 7) | 42 | - | 42 | - | - | - |
| Other assets | 47 | - | 47 | 47 | - | 47 |
| | $ 5,470 | $ 1,850 | $ 7,320 | $ 5,351 | $ 1,803 | $ 7,154 |

[2] Includes current portion.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

## 11. Segment information, continued:

The Company's revenues and other income from contracts with customers are disaggregated by major type of revenues and operational groupings of revenues:

| | Three months ended September 30, 2022 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Alberta Commercial | Western Canada Contracted | Ontario Contracted | U.S. Contracted | Total from contracts with customers | Other sources | Total |
| Energy revenues | $ 985 | $ 23 | $ 127 | $ 18 | $ 1,153 | $ (433) | $ 720 |
| Emission credit revenues | 4 | 3 | - | - | 7 | 8 | 15 |
| Total revenues[3] | $ 989 | $ 26 | $ 127 | $ 18 | $ 1,160 | (425) | $ 735 |

| | Nine months ended September 30, 2022 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Alberta Commercial | Western Canada Contracted | Ontario Contracted | U.S. Contracted | Total from contracts with customers | Other sources | Total |
| Energy revenues | $ 1,987 | $ 94 | $ 313 | $ 153 | $ 2,547 | $ (767) | $ 1,780 |
| Emission credit revenues | 18 | 7 | - | 3 | 28 | 30 | 58 |
| Total revenues[3] | $ 2,005 | $ 101 | $ 313 | $ 156 | $ 2,575 | (737) | $ 1,838 |

| | Three months ended September 30, 2021 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Alberta Commercial | Western Canada Contracted | Ontario Contracted | U.S. Contracted | Total from contracts with customers | Other sources | Total |
| Energy revenues | $ 398 | $ 18 | $ 81 | $ 13 | $ 510 | $ (192) | $ 318 |
| Emission credit revenues | 4 | 1 | - | - | 5 | 2 | 7 |
| Total revenues[3] | $ 402 | $ 19 | $ 81 | $ 13 | $ 515 | (190) | $ 325 |

| | Nine months ended September 30, 2021 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Alberta Commercial | Western Canada Contracted | Ontario Contracted | U.S. Contracted | Total from contracts with customers | Other sources | Total |
| Energy revenues | $ 1,204 | $ 59 | $ 221 | $ 133 | $ 1,617 | $ (484) | $ 1,133 |
| Emission credit revenues | 17 | 4 | - | 2 | 23 | (3) | 20 |
| Total revenues[3] | $ 1,221 | $ 63 | $ 221 | $ 135 | $ 1,640 | (487) | $ 1,153 |

[3] Included within trade and other receivables, at September 30, 2022, were amounts related to contracts with customers of $544 million (2021 - $195 million).

## 12. Comparative figures:

Certain comparative figures have been reclassified to conform to the current year's presentation.