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Capital Power
RESPONSIBLE ENERGY FOR TOMORROW

For immediate release | October 27, 2021

Capital Power reports third quarter results and reiterates its revised higher 2021 financial guidance

EDMONTON, Alberta – October 27, 2021 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended September 30, 2021.

Highlights

- Generated net cash flows from operating activities of $347 million and adjusted funds from operations (AFFO) of $206 million in the third quarter of 2021
- Generated net income of $38 million and adjusted EBITDA of $286 million in the third quarter of 2021
- Announced 15-year renewable power purchase agreement with Dow Chemical Canada ULC for a portion of our Whitla Wind 2 project, currently under construction in Alberta
- Continued constructive discussions for the re-contracting of the Island Generation facility
- Strong performance, financial position and outlook led to announced suspension of the Company's Dividend Re-investment Plan (DRIP)

"Our operating and financial results for the third quarter of 2021 were generally in line with management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "The unplanned outage at Genesee 2 that started in mid-July is running longer than anticipated with the asset currently expected to return to service at the end of November 2021. A claim has been submitted to our insurers for both the physical damage and business interruption losses incurred as a result of the incident which will be settled upon the return to service of the facility."

"Alberta power prices remain strong, averaging $100 per megawatt hour (MWh) in the third quarter, a period during which our trading desk captured an average realized power price of $75 per MWh. Our outlook for Alberta power prices continues to be positive and based on our forecast for the remainder of the year, we expect to generate adjusted EBITDA in line with the mid-point of our revised annual guidance range of $1,090 million to $1,140 million and AFFO modestly above the mid-point of our revised annual guidance range of $570 million to $620 million," stated Mr. Vaasjo.

Operational and Financial Highlights [1] (unaudited)	**Three months ended September 30**		**Nine months ended September 30**	
(millions of dollars except per share and operational amounts)	**2021**	**2020**	**2021**	**2020**
Electricity generation (Gigawatt hours)	6,103	6,327	16,708	17,361
Generation facility availability	91%	98%	90%	94%
Revenues and other income	$ 377	$ 453	$ 1,318	$ 1,421
Adjusted EBITDA [2]	$ 286	$ 284	$ 830	$ 735
Net income [3]	$ 38	$ 106	$ 156	$ 129
Net income attributable to shareholders of the Company [3]	$ 40	$ 108	$ 163	$ 133
Basic earnings per share [3]	$ 0.23	$ 0.89	$ 1.10	$ 0.87
Diluted earnings per share [3]	$ 0.23	$ 0.89	$ 1.09	$ 0.87
Normalized earnings attributable to common shareholders [2,3]	$ 63	$ 69	$ 166	$ 115
Normalized earnings per share [2, 3]	$ 0.55	$ 0.66	$ 1.50	$ 1.09
Net cash flows from operating activities	$ 347	$ 258	$ 682	$ 452
Adjusted funds from operations [2]	$ 206	$ 221	$ 456	$ 436
Adjusted funds from operations per share [2]	$ 1.78	$ 2.10	$ 4.12	$ 4.14
Purchase of property, plant and equipment and other assets, net	$ 176	$ 67	$ 424	$ 253
Dividends per common share, declared	$ 0.5475	$ 0.5125	$ 1.5725	$ 1.4725

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, 2021.

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, normalized earnings per share, AFFO and AFFO per share are non-GAAP financial measures and 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.

3 Includes depreciation and amortization for the three months ended September 30, 2021 and 2020 of $133 million and $115 million, respectively, and for the nine months ended September 30, 2021 and 2020 of $402 million and $356 million, respectively. Forecasted depreciation and amortization for the remainder of 2021 is $139 million.

Significant Events

Executed 15-year contract for Whitla Wind 2

On September 15, 2021, the Company announced a 15-year renewable power purchase agreement with Dow Chemical Canada ULC, a subsidiary of Dow, for 25 MW of capacity and the associated environmental attributes from our Whitla Wind 2 project, currently under construction.

Forced outage at Genesee 2

In July 2021, Genesee 2 experienced a forced outage due to a generator failure which is covered by the Company's insurance policy for both asset damage and business interruption. The unit is undergoing repairs and expected to return to service in the latter part of the fourth quarter of 2021. Accrued insurance recoveries, net of related expenses, of $16 million have been recorded in the third quarter of 2021. Accrued insurance recoveries reflect both the expensed costs and capitalized costs incurred to date to repair Genesee 2, net of the deductible amount under the insurance contract.

Dividend increase

On July 29, 2021, the Company's Board of Directors approved an increase of 6.8% in the annual dividend for holders of its common shares, from $2.05 per common share to $2.19 per common share. This increased common share dividend will commence with the third quarter 2021 quarterly dividend payment on October 29, 2021 to shareholders of record at the close of business on September 30, 2021.

US$150 million private placement of senior notes

On July 20, 2021, the Company executed a US$150 million private placement of senior notes. The 12-year senior notes will bear a coupon rate of 3.24% and mature on October 28, 2033. Subject to satisfying customary closing conditions, the transaction is expected to fund on October 28, 2021. The net proceeds from the transaction will be used to fund growth initiatives including 985 megawatts (MW) in advanced stages of development and for general corporate purposes.

Sustainability-linked credit facilities

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

Common share offering

In June of 2021 the Company completed a public offering of 7,480,750 common shares (inclusive of the full exercise of a 975,750 common shares over-allotment option), at an issue price of $38.45 per common share for total gross proceeds of $288 million (the Offering) less issue costs of $12 million. The Company intends to use the net proceeds from the Offering to fund growth initiatives (including projects in advanced stages of development) and for general corporate purposes.

Executive appointments

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

- Bryan DeNeve, Senior Vice President Operations,
- Chris Kopecky, Senior Vice President and Chief Legal, Development and Commercial Officer, and
- Steve Owens, Senior Vice President Construction and Engineering.

Kate Chisholm, Sandra Haskins and Jacquie Pylypiuk continue to serve in their current roles. Darcy Trufyn, Senior Vice President, Operations, Engineering and Construction retired from his role effective June 30, 2021. Darcy was an integral part of the executive team with outstanding service and valuable contributions over the past twelve years.

Executed 15-year contract for Enchant Solar project

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

Construction of Enchant Solar is set to commence in the second quarter of 2022 with commercial operations expected in the fourth quarter of 2022.

United States power operations relating to extreme weather event

During the February 9 to 20, 2021 period, extreme winter weather caused some disruptions to our wind facilities, most notably in Texas (Buckthorn Wind) with no significant impact on the balance of Capital Power's U.S. operations. Buckthorn Wind experienced no significant physical damage, but some turbines were forced offline. As of February 22, 2021, the operations were back to normal. The net impact of the U.S. storm on Buckthorn Wind resulted in increases of $8 million (US$6 million) to adjusted EBITDA and AFFO. In addition, during the peak days of the weather event, the Company was able to leverage its commodity management expertise to physically flow power around North America to contribute a further positive financial impact.

The favourable impacts of the weather event were largely driven by the settlement of the offtake and commodity swaps for Buckthorn Wind for the noted period of extreme weather. However, Buckthorn Wind's counterparty is contesting the settlement, arguing that settlement should have been based upon a different reference price. Historically these two prices have been similar, but as a result of the recent extreme weather, the Company became aware of a divergence in these prices during scarcity events. Both parties invoked dispute-resolution procedures during the first quarter of 2021 and the Company subsequently initiated litigation. Based on the contract terms of the offtake and commodity swaps, the Company considers the probability of ultimate settlement using the reference price advocated by the counterparty as being unlikely. In the event that the dispute is resolved unfavourably to the Company, the net exposure to the Company's revenues would be a reduction of up to approximately $18 million (US$15 million).

Approval of normal course issuer bid

During the first quarter of 2021, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 10.7 million of its outstanding common shares during the one-year period from February 26, 2021 to February 25, 2022.

Subsequent Event

Suspension of Dividend Re-investment Plan

Subsequent to the close of the third quarter of 2021, Capital Power announced that effective with the December 31, 2021 dividend, its DRIP for its common shares will be suspended. Shareholders participating in the DRIP will begin receiving cash dividends on the January 31, 2022 payment date.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 27, 2021 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

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

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 is as follows:

(unaudited, $ millions)	Three months ended							
	Sep 30 2021	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Revenues and other income	377	387	554	516	453	435	533	683
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(162)	(176)	(264)	(321)	(144)	(233)	(323)	(309)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	66	24	7	19	(31)	9	18	(28)
Adjusted EBITDA from joint venture [1]	5	6	6	6	6	6	6	6
Adjusted EBITDA	**286**	**241**	**303**	**220**	**284**	**217**	**234**	**352**
Depreciation and amortization	(133)	(132)	(137)	(122)	(115)	(121)	(120)	(118)
Unrealized changes in fair value of commodity derivatives and emission credits	(66)	(24)	(7)	(19)	31	(9)	(18)	28
Impairment (losses) reversal	(8)	2	-	(13)	-	-	(13)	-
Gains (losses) on disposals and other transactions	31	(3)	2	-	-	-	-	24
Foreign exchange (loss) gain	(7)	(2)	1	5	1	3	(9)	-
Net finance expense	(43)	(46)	(41)	(57)	(47)	(49)	(44)	(41)
Finance expense and depreciation expense from joint venture [1]	(4)	(5)	-	(4)	(4)	(6)	(13)	(1)
Income tax expense	(18)	(14)	(20)	(9)	(44)	(12)	(17)	(63)
Net income	**38**	**17**	**101**	**1**	**106**	**23**	**-**	**181**
Net income (loss) attributable to:								
Non-controlling interests	(2)	(3)	(2)	(2)	(2)	-	(2)	(1)
Shareholders of the Company	40	20	103	3	108	23	2	182
Net income	**38**	**17**	**101**	**1**	**106**	**23**	**-**	**181**

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

Adjusted funds from operations and adjusted funds from operations per share

AFFO is a measure 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 coal compensation that will be received annually,
- remove the tax equity financing project investors' shares of adjusted funds from operations 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.

AFFO per share is determined by applying AFFO to the weighted average number of common shares used in the calculation of basic, diluted and normalized earnings per share.

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**	
	2021	**2020**	**2021**	**2020**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**347**	**258**	**682**	**452**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	37	39	98	101
Realized gains on settlement of interest rate derivatives	-	-	(12)	(1)
Change in fair value of derivatives reflected as cash settlement	6	8	17	26
Distributions received from joint venture	(3)	(3)	(8)	(8)
Miscellaneous financing charges paid [1]	1	1	4	4
Income taxes (recovered) paid	(18)	5	(13)	38
Change in non-cash operating working capital	(120)	(65)	(105)	(12)
	(97)	(15)	(19)	148
Net finance expense [2]	(29)	(35)	(93)	(106)
Current income tax expense [3]	(3)	(10)	(19)	(26)
Sustaining capital expenditures [4]	(52)	(16)	(99)	(50)
Preferred share dividends paid	(12)	(13)	(38)	(39)
Cash received for off-coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(1)	(2)	(7)	(6)
Adjusted funds from operations from joint venture	3	4	12	13
Line Loss Rule Proceeding [5]	-	-	(13)	-
Adjusted funds from operations	**206**	**221**	**456**	**436**
Weighted average number of common shares outstanding (millions)	**115.5**	**105.1**	**110.7**	**105.2**
Adjusted funds from operations per share ($)	**1.78**	**2.10**	**4.12**	**4.14**

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 (three and nine months ended September 30, 2020 excludes current income tax recoveries of nil and $20 million, respectively).

4 Includes sustaining capital expenditures net of partner contributions of $1 million and $8 million for the three and nine months ended September 30, 2021, respectively, compared with $1 million and $4 million for the three and nine months ended September 30, 2020, respectively.

5 The LLR Proceeding invoicing process has resulted in gross billings to Capital Power of which amounts not attributable to Capital Power have been partly recovered from the appropriate parties for their respective shares. For the three and nine months ended September 30, 2021, actual net cash inflows of $2 and outflows of $33 million, respectively, for the LLR Proceeding amounts are reflected in net cash flows from operating activities through the change in non-cash operating working capital, which is removed in the calculation of AFFO. AFFO for the three and nine months ended September 30, 2021, is impacted only by the Company's obligation related to the 2006-2009 and 2010-2013 invoice tranches (nil and $13 million for the three and nine months ended September 30, 2021, respectively) consistent with the Company's definition of AFFO described above. The AFFO impacts differ from the actual cash outflows by the amounts paid by the Company but expected to be recovered from other parties (see Contingent Liabilities 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 per share is based on earnings (loss) used in the calculation of basic earnings (loss) per share 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 30 2021	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Basic earnings (loss) per share ($)	**0.23**	**0.05**	**0.83**	**(0.09)**	**0.89**	**0.10**	**(0.11)**	**1.61**
Net income attributable to shareholders of the Company per condensed interim consolidated statements of income	**40**	**20**	**103**	**3**	**108**	**23**	**2**	**182**
Preferred share dividends including Part VI.1 tax	(13)	(14)	(14)	(13)	(14)	(13)	(14)	(12)
Earnings (loss) attributable to common shareholders	27	6	89	(10)	94	10	(12)	170
Unrealized changes in fair value of derivatives [1]	48	25	(10)	12	(28)	3	30	(28)
Genesee 2 forced outage[2]	(12)	-	-	-	-	-	-	-
Provision for contingency	(6)	6	-	-	-	-	-	-
Impairment (reversal) losses	6	(2)	-	10	-	-	10	-
Reduction in applicable jurisdictional tax rates	-	-	(10)	-	-	-	-	-
Provision for Line Loss Rule Proceeding [3]	-	-	(1)	1	-	3	-	4
Net gain on swap transaction	-	-	-	-	-	-	-	(115)
Other	-	-	-	-	3	2	-	-
Normalized earnings attributable to common shareholders	**63**	**35**	**68**	**13**	**69**	**18**	**28**	**31**
Weighted average number of common shares outstanding (millions)	115.5	109.7	106.8	105.7	105.1	105.1	105.4	105.3
Normalized earnings per share ($)	**0.55**	**0.32**	**0.64**	**0.12**	**0.66**	**0.17**	**0.27**	**0.29**

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

2 See Significant Events.

3 See Contingent Liabilities and Provisions.

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 2021 AFFO and adjusted EBITDA guidance, (ii) forecasted depreciation for the remainder of 2021, (iii) the intended use of proceeds from the common share offering (see Significant Events), (iv) expectations pertaining to the financial guidance, timing of construction and timing of commercial operations commencement of Enchant Solar (see Significant Events), (v) expectations around the resolution of the pricing dispute on the Buckthorn Wind offtake and commodity swaps (see Significant Events), (vi) the intended use of proceeds and expected closing date of the U.S. private placement of senior notes (see Significant Events), (vii) matters relating to the LLR Proceeding, including the recovery from appropriate parties and (viii) the expected timing of Genesee 2 returning to service (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 the need for and potential re-contracting of facilities) and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) matters relating to the LLR Proceeding, including the recovery and timing thereof from appropriate parties.

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 the Company's Management's Discussion and Analysis for both the nine months ended September 30, 2021, prepared as of October 26, 2021 and the Company's Integrated Annual Report for the year ended December 31, 2020, prepared as of February 18, 2021, 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 over 6,400 MW of power generation capacity at 26 facilities across North America. Projects in advanced development include 425 MW of owned renewable generation capacity in North Carolina and Alberta and 560 MW of incremental natural gas combined cycle capacity from the repowering of Genesee 1 and 2 in Alberta.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A), prepared as of October 26, 2021, 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, 2021, 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, 2020 (the 2020 Integrated Annual Report), the Annual Information Form of Capital Power Corporation dated February 23, 2021, and the cautionary statements regarding forward-looking information which begin on page 10.

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, 2021 and the nine months ended September 30, 2020 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 26, 2021.

Contents

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 2021 performance targets and related 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, 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 and dividends;
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings;
- the timing and costs for development projects (including the repowering of Genesee 1 and 2, phases 2 and 3 of Whitla Wind, Strathmore Solar, Bear Branch Solar, Hornet Solar, Hunter's Cove Solar and Enchant Solar);
- facility availability and planned outages;
- the anticipated return to service date of Genesee 2 (see Significant Events);
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects, commercial initiatives);
- the impact of market designs on the Company's core markets;
- matters related to the Line Loss Rule (LLR) Proceeding including recovery from appropriate parties and potential impacts to the Company arising from the foregoing;
- the resolution of the pricing dispute on the Buckthorn Wind offtake and commodity swaps (see Significant Events);
- the intended use of proceeds of the common share offering (see Significant Events);
- the intended use of proceeds and expected closing date of the U.S. private placement of senior notes (see Significant Events); and
- the impact of the COVID-19 pandemic.

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, other energy, and carbon prices;
- performance;
- business prospects (including the need for and 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 recovery and timing thereof 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;
- 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;
- 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 2020 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 over 6,400 megawatts (MW) of power generation capacity at 26 facilities across North America. Projects in advanced development include 425 MW of owned renewable generation capacity in North Carolina and Alberta and 560 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 remains consistent with that disclosed in its 2020 Integrated Annual Report.

PERFORMANCE OVERVIEW

The Company measures its performance in relation to its corporate strategy 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	2021 target	Actual results for the nine months ended September 30, 2021
Facility availability average	93% or greater	90%
Sustaining capital expenditures	$80 to $90 million	$99 million [1]

[1] Includes sustaining capital expenditures net of joint venture contributions of $8 million.

The Company's facility availability averaged 90% which reflected planned outages at Clover Bar Energy Centre, Joffre, Shepard, York Energy, Goreway, Decatur Energy and Arlington Valley. Unplanned outages also occurred at Genesee, Island Generation and Decatur Energy. Full year facility availability is expected to be below target driven by the Genesee 2 unplanned outage.

Sustaining capital expenditures for the nine months ended September 30, 2021 were higher than target year to date primarily due to additional spend related to the Genesee 2 unplanned outage for which insurance recoveries will be received and have been accrued within the statement of income as gains on disposals and other transactions. Full year sustaining capital expenditures will be above the target range due largely to additional costs incurred on the Arlington Valley planned outage.

Disciplined growth

Performance measure	2021 target	Status as at September 30, 2021
Repowering of Genesee 1 and 2	Pending regulatory approval, expect construction to begin in the third quarter of 2021, with an anticipated in-service date in late 2023 for the repowered Genesee 1 and 2024 for Genesee 2.	All regulatory approvals have been received and construction commenced in 2021. The anticipated in-service dates remain consistent with target.
Renewable projects:	Target completion dates on time and on budget for 2021 projects and progress on the development of 2022 projects to be on track with budget and completion dates.	Strathmore Solar and Enchant Solar are facing cost pressures and are now expected to be over target (see Liquidity and Capital Resources). The target completion dates for Hornet Solar, Hunter's Cove Solar and Bear Branch Solar have moved as a result of delays in the interconnection process and are now expected to be in the fourth quarter of 2023 or the first quarter of 2024. Aside from these noted exceptions to projected spending and timing, the projects remain on budget and on track with their targeted in-service dates.
Whitla Wind 2 (Alberta)	Fourth quarter of 2021	
Whitla Wind 3 (Alberta)	Fourth quarter of 2021	
Strathmore Solar (Alberta)	Early 2022	
Enchant Solar (Alberta)	Fourth quarter of 2022	
Hornet Solar (North Carolina)	Fourth quarter of 2022	
Hunter's Cove Solar (North Carolina)	Fourth quarter of 2022	
Bear Branch Solar (North Carolina)	Fourth quarter of 2022	
Other growth	$500 million of committed capital	The Company continues to explore growth opportunities to achieve this target during the year.

Financial stability and strength

Performance measure[1]	2021 target	2021 updated guidance [3]	Actual results to September 30, 2021
Adjusted funds from operations	$500 million to $550 million [2]	$570 million to $620 million	$456 million
Adjusted EBITDA	$975 million to $1,025 million	$1,090 million to $1,140 million	$830 million

1 AFFO and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures.

2 Target excludes impact from the LLR Proceeding. Actual results for the nine months ended September 30, 2021, as well as the 2021 updated guidance, reflect a cash outflow of $13 million related to the LLR Proceeding.

3 Upon release of the Company's second quarter results and based on the Company's year-to-date results and expectations for the remainder of the year at that time, the Company provided updated guidance for 2021 (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 its Investor Day held in December 2020, the Company provided financial guidance for 2021 AFFO in the range of $500 million to $550 million and 2021 adjusted EBITDA in the range of $975 million to $1,025 million (see Non-GAAP Financial Measures). At the time of release of the Company's second quarter results, based on the actual results for the first half of 2021 and the Company's forecast for the back half of the year, the Company adjusted its guidance for AFFO and adjusted EBITDA for 2021 to be in the range of $570 million to $620 million for AFFO and $1,090 million to $1,140 million for adjusted EBITDA. The increased guidance ranges were driven most notably by the strength of the Alberta power market, inclusive of actual performance in the first half of 2021 and expectations for the back half of 2021. The updated guidance ranges considered the Company's existing Alberta portfolio position for the remainder of the year as well as strong forward pricing for our remaining Alberta generation. Additionally, the estimated impacts of the Genesee 2 outage that occurred subsequent to the close of the second quarter were included in the updated guidance ranges. Based on results for the third quarter of 2021 and expectations for the final quarter of 2021, the Company expects full year results to be in line with the mid-point of the new guidance range for adjusted EBITDA and modestly above the mid-point of the new guidance range for AFFO.

Priorities for the Company in 2021 include supporting our sustainability targets through the development of the Genesee Carbon Conversion Centre, exploration of carbon capture, utilization and storage development opportunities and the strategic development of natural gas and renewable assets. This includes advancing the repowering of Genesee 1 and 2 and ongoing development of our wind and solar projects.

In 2021, Capital Power's availability target of 93% reflects major scheduled maintenance outages for Genesee 2, Decatur Energy and Shepard compared to those scheduled for Genesee 2 (subsequently deferred to 2021), Arlington Valley, Decatur Energy and Southport in 2020.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2022, 2023 and 2024 (all as at September 30, 2021) were:

Alberta commercial portfolio positions and power prices	Full year 2022	Full year 2023	Full year 2024
Percentage of baseload generation sold forward [1]	67%	38%	21%
Contracted price [2]	Mid-$60	High-$50	Mid-$50
Forward Alberta pool prices	$88	$70	$61

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.

The 2021 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. However, 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 its Investor Day held in December 2020, the Company confirmed its annual dividend growth guidance for 2021 and 2022 at 7% and 5%, respectively, with the 2021 increase of 6.8% subsequently approved in July 2021. Each annual increase is subject to changing circumstances and 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. The Company significantly reduced financing risk for its current growth initiatives, including 985 MW in advanced stages of development, with the financing activities completed to date in 2021 (see Significant Events and Subsequent Event). Outside of new growth opportunities the Company does not expect additional equity offerings will be required to fund growth.

NON-GAAP FINANCIAL MEASURES

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, (iii) AFFO per share, (iv) normalized earnings attributable to common shareholders, and (v) normalized earnings per share as financial performance measures.

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 is as follows:

(unaudited, $ millions)	Three months ended							
	Sep 30 2021	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Revenues and other income	377	387	554	516	453	435	533	683
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(162)	(176)	(264)	(321)	(144)	(233)	(323)	(309)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	66	24	7	19	(31)	9	18	(28)
Adjusted EBITDA from joint venture [1]	5	6	6	6	6	6	6	6
Adjusted EBITDA	**286**	**241**	**303**	**220**	**284**	**217**	**234**	**352**
Depreciation and amortization	(133)	(132)	(137)	(122)	(115)	(121)	(120)	(118)
Unrealized changes in fair value of commodity derivatives and emission credits	(66)	(24)	(7)	(19)	31	(9)	(18)	28
Impairment (losses) reversal	(8)	2	-	(13)	-	-	(13)	-
Gains (losses) on disposals and other transactions	31	(3)	2	-	-	-	-	24
Foreign exchange (loss) gain	(7)	(2)	1	5	1	3	(9)	-
Net finance expense	(43)	(46)	(41)	(57)	(47)	(49)	(44)	(41)
Finance expense and depreciation expense from joint venture [1]	(4)	(5)	-	(4)	(4)	(6)	(13)	(1)
Income tax expense	(18)	(14)	(20)	(9)	(44)	(12)	(17)	(63)
Net income	**38**	**17**	**101**	**1**	**106**	**23**	**-**	**181**
Net income (loss) attributable to:								
Non-controlling interests	(2)	(3)	(2)	(2)	(2)	-	(2)	(1)
Shareholders of the Company	40	20	103	3	108	23	2	182
Net income	**38**	**17**	**101**	**1**	**106**	**23**	**-**	**181**

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

Adjusted funds from operations and adjusted funds from operations per share

AFFO is a measure 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 coal compensation that will be received annually,

- remove the tax equity financing project investors' shares of adjusted funds from operations 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 LLR Proceeding invoices in the period each tranche is paid by the Company.

AFFO per share is determined by applying AFFO to the weighted average number of common shares used in the calculation of basic, diluted and normalized earnings per share.

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	
	2021	**2020**	**2021**	**2020**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**347**	**258**	**682**	**452**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	37	39	98	101
Realized gains on settlement of interest rate derivatives	-	-	(12)	(1)
Change in fair value of derivatives reflected as cash settlement	6	8	17	26
Distributions received from joint venture	(3)	(3)	(8)	(8)
Miscellaneous financing charges paid [1]	1	1	4	4
Income taxes (recovered) paid	(18)	5	(13)	38
Change in non-cash operating working capital	(120)	(65)	(105)	(12)
	(97)	(15)	(19)	148
Net finance expense [2]	(29)	(35)	(93)	(106)
Current income tax expense [3]	(3)	(10)	(19)	(26)
Sustaining capital expenditures [4]	(52)	(16)	(99)	(50)
Preferred share dividends paid	(12)	(13)	(38)	(39)
Cash received for off-coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(1)	(2)	(7)	(6)
Adjusted funds from operations from joint venture	3	4	12	13
Line Loss Rule Proceeding [5]	-	-	(13)	-
Adjusted funds from operations	**206**	**221**	**456**	**436**
Weighted average number of common shares outstanding (millions)	**115.5**	**105.1**	**110.7**	**105.2**
Adjusted funds from operations per share ($)	**1.78**	**2.10**	**4.12**	**4.14**

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 (three and nine months ended September 30, 2020 excludes current income tax recoveries of nil and $20 million, respectively).

4 Includes sustaining capital expenditures net of partner contributions of $1 million and $8 million for the three and nine months ended September 30, 2021, respectively, compared with $1 million and $4 million for the three and nine months ended September 30, 2020, respectively.

5 The LLR Proceeding invoicing process has resulted in gross billings to Capital Power of which amounts not attributable to Capital Power have been partly recovered from the appropriate parties for their respective shares. For the three and nine months ended September 30, 2021, actual net cash inflows of $2 million and outflows of $33 million, respectively, for the LLR Proceeding amounts are reflected in net cash flows from operating activities through the change in non-cash operating working capital, which is removed in the calculation of AFFO. AFFO for the three and nine months ended September 30, 2021, is impacted only by the Company's obligation related to the 2006-2009 and 2010-2013 invoice tranches (nil and $13 million for the three and nine months ended September 30, 2021, respectively) consistent with the Company's definition of AFFO described above. The AFFO impacts differ from the actual cash outflows by the amounts paid by the Company but expected to be recovered from other parties (see Contingent Liabilities 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 per share is based on earnings (loss) used in the calculation of basic earnings (loss) per share 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 30 2021	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Basic earnings (loss) per share ($)	**0.23**	**0.05**	**0.83**	**(0.09)**	**0.89**	**0.10**	**(0.11)**	**1.61**
Net income attributable to shareholders of the Company per condensed interim consolidated statements of income	**40**	**20**	**103**	**3**	**108**	**23**	**2**	**182**
Preferred share dividends including Part VI.1 tax	(13)	(14)	(14)	(13)	(14)	(13)	(14)	(12)
Earnings (loss) attributable to common shareholders	27	6	89	(10)	94	10	(12)	170
Unrealized changes in fair value of derivatives [1]	48	25	(10)	12	(28)	3	30	(28)
Genesee 2 forced outage[2]	(12)	-	-	-	-	-	-	-
Provision for contingency	(6)	6	-	-	-	-	-	-
Impairment (reversal) losses	6	(2)	-	10	-	-	10	-
Reduction in applicable jurisdictional tax rates	-	-	(10)	-	-	-	-	-
Provision for Line Loss Rule Proceeding [3]	-	-	(1)	1	-	3	-	4
Net gain on swap transaction	-	-	-	-	-	-	-	(115)
Other	-	-	-	-	3	2	-	-
Normalized earnings attributable to common shareholders	**63**	**35**	**68**	**13**	**69**	**18**	**28**	**31**
Weighted average number of common shares outstanding (millions)	115.5	109.7	106.8	105.7	105.1	105.1	105.4	105.3
Normalized earnings per share ($)	**0.55**	**0.32**	**0.64**	**0.12**	**0.66**	**0.17**	**0.27**	**0.29**

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

2 See Significant Events.

3 See Contingent Liabilities and Provisions.

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Revenues and other income	377	453	1,318	1,421
Adjusted EBITDA [1]	286	284	830	735
Net income	38	106	156	129
Net income attributable to shareholders of the Company	40	108	163	133
Normalized earnings attributable to common shareholders [1]	63	69	166	115
Basic earnings per share ($)	0.23	0.89	1.10	0.87
Diluted earnings per share ($) [2]	0.23	0.89	1.09	0.87
Normalized earnings per share ($) [1]	0.55	0.66	1.50	1.09
Net cash flows from operating activities	347	258	682	452
Adjusted funds from operations [1]	206	221	456	436
Adjusted funds from operations per share ($) [1]	1.78	2.10	4.12	4.14
Purchase of property, plant and equipment and other assets, net	176	67	424	253
Dividends per common share, declared ($)	0.5475	0.5125	1.5725	1.4725
Dividends per Series 1 preferred share, declared ($)	0.1638	0.1913	0.4914	0.5738
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 ($)	0.3750	0.3750	1.1250	1.1250
Dividends per Series 9 preferred share, declared ($)	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, 2021	December 31, 2020
Loans and borrowings including current portion	2,962	3,552
Total assets	8,879	8,911

[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.

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

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 net income per share and normalized earnings per share described under Non-GAAP Financial Measures.

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, 2021 was lower than the corresponding period in 2020 mainly due to: lower AFFO from our U.S. contracted facilities; higher sustaining capital expenditures, net of accrued insurance recoveries on the sustaining capital expenditures related to the Genesee 2 forced outage; and lower net finance expense impacting AFFO in 2021. AFFO for the nine months ended September 30, 2021 was higher than the corresponding period in 2020 primarily due to higher AFFO from our Alberta Commercial facilities, mainly due to higher realized power pricing, and lower net finance expense impacting AFFO in 2021. These increases were partially offset by lower AFFO from our U.S. and Ontario contracted facilities, the AFFO impact of the second and third tranches of LLR Proceeding invoices paid during the period and higher sustaining capital expenditures, net of accrued insurance recoveries, in 2021. Additional details pertaining to operational variances described above can be found in the respective sections in Consolidated Net Income and Results of Operations.

The increase in purchases of property, plant and equipment and other assets is discussed in Liquidity and Capital Resources.

SIGNIFICANT EVENTS

Executed 15-year contract for Whitla Wind 2

On September 15, 2021, the Company announced a 15-year renewable power purchase agreement with Dow Chemical Canada ULC, a subsidiary of Dow, for 25 MW of capacity and the associated environmental attributes from our Whitla Wind 2 project, currently under construction.

Forced outage at Genesee 2

In July 2021, Genesee 2 experienced a forced outage due to a generator failure which is covered by the Company's insurance policy for both asset damage and business interruption. The unit is undergoing repairs and expected to return to service in the latter part of the fourth quarter of 2021. Accrued insurance recoveries, net of related expenses, of $16 million have been recorded in the third quarter of 2021. Accrued insurance recoveries reflect both the expensed costs and capitalized costs incurred to date to repair Genesee 2, net of the deductible amount under the insurance contract.

Dividend increase

On July 29, 2021, the Company's Board of Directors approved an increase of 6.8% in the annual dividend for holders of its common shares, from $2.05 per common share to $2.19 per common share. This increased common share dividend will commence with the third quarter 2021 quarterly dividend payment on October 29, 2021 to shareholders of record at the close of business on September 30, 2021.

US$150 million private placement of senior notes

On July 20, 2021, the Company executed a US$150 million private placement of senior notes. The 12-year senior notes will bear a coupon rate of 3.24% and mature on October 28, 2033. Subject to satisfying customary closing conditions, the transaction is expected to fund on October 28, 2021. The net proceeds from the transaction will be used to fund growth initiatives including 985 MW in advanced stages of development and for general corporate purposes.

Sustainability-linked credit facilities

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

Common share offering

In June of 2021 the Company completed a public offering of 7,480,750 common shares (inclusive of the full exercise of a 975,750 common shares over-allotment option), at an issue price of $38.45 per common share for total gross proceeds of approximately $288 million (the Offering) less issue costs of $12 million. The Company intends to use the net proceeds from the Offering to fund growth initiatives (including projects in advanced stages of development) and for general corporate purposes.

Executive appointments

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

- Bryan DeNeve, Senior Vice President Operations,
- Chris Kopecky, Senior Vice President and Chief Legal, Development and Commercial Officer, and
- Steve Owens, Senior Vice President Construction and Engineering.

Kate Chisholm, Sandra Haskins and Jacquie Pylypiuk continue to serve in their current roles. Darcy Trufyn, Senior Vice President, Operations, Engineering and Construction retired from his role effective June 30, 2021. Darcy was an integral part of the executive team with outstanding service and valuable contributions over the past twelve years.

Executed 15-year contract for Enchant Solar project

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

Construction of Enchant Solar is set to commence in the second quarter of 2022 with commercial operations expected in the fourth quarter of 2022.

United States power operations relating to extreme weather event

During the February 9 to 20, 2021 period, extreme winter weather caused some disruptions to our wind facilities, most notably in Texas (Buckthorn Wind) with no significant impact on the balance of Capital Power's U.S. operations. Buckthorn Wind experienced no significant physical damage, but some turbines were forced offline. As of February 22, 2021, the operations were back to normal. The net impact of the U.S. storm on Buckthorn Wind resulted in increases of $8 million (US$6 million) to adjusted EBITDA and AFFO. In addition, during the peak days of the weather event, the Company was able to leverage its commodity management expertise to physically flow power around North America to contribute a further positive financial impact.

The favourable impacts of the weather event were largely driven by the settlement of the offtake and commodity swaps for Buckthorn Wind for the noted period of extreme weather. However, Buckthorn Wind's counterparty is contesting the settlement, arguing that settlement should have been based upon a different reference price. Historically these two prices have been similar, but as a result of the recent extreme weather, the Company became aware of a divergence in these prices during scarcity events. Both parties invoked dispute-resolution procedures during the first quarter of 2021 and the Company subsequently initiated litigation. Based on the contract terms of the offtake and commodity swaps, the Company considers the probability of ultimate settlement using the reference price advocated by the counterparty as being unlikely. In the event that the dispute is resolved unfavourably to the Company, the net exposure to the Company's revenues would be a reduction of up to approximately $18 million (US$15 million).

Approval of normal course issuer bid

During the first quarter of 2021, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 10.7 million of its outstanding common shares during the one-year period from February 26, 2021 to February 25, 2022.

SUBSEQUENT EVENT

Suspension of Dividend Re-investment Plan

Subsequent to the close of the third quarter of 2021, Capital Power announced that effective with the December 31, 2021 dividend, its Dividend Re-investment Plan (DRIP) for its common shares will be suspended. Shareholders participating in the DRIP will begin receiving cash dividends on the January 31, 2022 payment date.

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, 2021 compared with 2020 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, 2020		**106**		**129**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	1		64	
Western Canada contracted facilities	(2)		(6)	
Ontario contracted facilities	1		(7)	
U.S. contracted facilities	(11)		(8)	
Corporate	13	2	52	95
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(97)		(101)
Gains on disposals and other transactions		31		30
Increase in depreciation and amortization expense		(18)		(46)
(Increase) decrease in impairments		(8)		7
Change in foreign exchange gain/(loss)		(8)		(3)
Decrease in finance expense and depreciation expense from joint venture		-		14
Decrease in net finance expense		4		10
Increase (decrease) in income before tax		(94)		6
Decrease in income tax expense		26		21
Increase (decrease) in net income		**(68)**		**27**
Consolidated net income for the periods ended September 30, 2021		**38**		**156**

Results by facility category and other

	Three months ended September 30							
	2021	2020	2021	2020	2021	2020	2021	2020
	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	6,103	6,327	91	98	539	407		
Alberta commercial facilities [4]								
Genesee 1	824	739	94	100	82	35		
Genesee 2	156	696	19	100	24	31		
Genesee 3	1,009	1,014	99	100	100	44		
Clover Bar Energy Centre 1, 2 and 3	235	98	97	98	32	10		
Joffre	166	171	92	99	25	13		
Shepard	739	784	100	100	52	33		
Halkirk Wind	98	117	96	96	13	9		
Clover Bar Landfill Gas	-	1	24	37	-	-		
Alberta commercial facilities	3,227	3,620	83	99	328	175		
Portfolio optimization	N/A	N/A	N/A	N/A	(15)	99		
	3,227	3,620	83	99	313	274	132	131
Western Canada contracted facilities [4,5]								
Island Generation	424	47	96	100	9	10		
Quality Wind	101	108	96	98	12	12		
EnPower	-	2	100	100	-	-		
Whitla Wind 1	156	170	95	98	7	7		
	681	327	96	99	28	29	20	22
Ontario contracted facilities [5]								
York Energy [6]	6	4	87	98	N/A	N/A		
East Windsor	4	2	100	99	8	8		
Goreway	453	329	100	93	66	52		
Kingsbridge 1	13	15	99	98	1	2		
Port Dover and Nanticoke Wind	47	53	90	93	7	8		
	523	403	97	94	82	70	53	52
U.S. contracted facilities								
Roxboro, North Carolina [7]	N/A	84	N/A	99	N/A	10		
Southport, North Carolina [7]	N/A	100	N/A	98	N/A	16		
Decatur Energy, Alabama	381	665	94	100	34	36		
Arlington Valley, Arizona	876	693	100	99	36	36		
Beaufort Solar, North Carolina	8	8	96	99	1	1		
Bloom Wind, Kansas	132	154	90	95	7	10		
Macho Springs Wind, New Mexico	15	21	97	97	1	2		
New Frontier Wind, North Dakota	92	95	95	97	5	8		
Cardinal Point Wind, Illinois [8]	93	86	96	92	12	9		
Buckthorn Wind, Texas [9]	75	71	96	94	5	5		
	1,672	1,977	96	98	101	133	85	96
Corporate [10]					32	13	(4)	(17)
Unrealized changes in fair value of commodity derivatives and emission credits					(179)	(66)		
Consolidated revenues and other income and adjusted EBITDA					**377**	**453**	**286**	**284**

	Nine months ended September 30							
	2021	2020	2021	2020	2021	2020	2021	2020
	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	16,708	17,361	90	94	1,620	1,203		
Alberta commercial facilities [4]								
Genesee 1	2,148	2,220	93	99	223	103		
Genesee 2	1,438	2,087	72	98	165	93		
Genesee 3	2,864	2,853	96	96	288	135		
Clover Bar Energy Centre 1, 2 and 3	325	373	97	95	54	35		
Joffre	549	489	96	97	78	42		
Shepard	1,921	2,421	83	100	143	105		
Halkirk Wind	360	386	97	98	46	33		
Clover Bar Landfill Gas	-	3	8	46	-	-		
Alberta commercial facilities	9,605	10,832	89	97	997	546		
Portfolio optimization	N/A	N/A	N/A	N/A	(27)	245		
	9,605	10,832	89	97	970	791	433	369
Western Canada contracted facilities [4,5]								
Island Generation	566	54	95	100	27	29		
Quality Wind	311	329	97	97	37	37		
EnPower	18	15	94	87	1	1		
Whitla Wind 1	569	600	97	97	25	26		
	1,464	998	96	98	90	93	67	73
Ontario contracted facilities [5]								
York Energy [6]	15	11	96	99	N/A	N/A		
East Windsor	8	5	99	98	23	24		
Goreway	846	689	96	92	171	152		
Kingsbridge 1	63	68	99	98	5	6		
Port Dover and Nanticoke Wind	194	213	96	97	29	31		
	1,126	986	96	94	228	213	159	166
U.S. contracted facilities								
Roxboro, North Carolina [7]	57	249	100	96	7	30		
Southport, North Carolina [7]	60	319	100	94	11	50		
Decatur Energy, Alabama	977	1,116	75	87	70	72		
Arlington Valley, Arizona	1,882	1,474	92	81	95	90		
Beaufort Solar, North Carolina	22	22	98	100	2	2		
Bloom Wind, Kansas	474	549	94	97	25	33		
Macho Springs Wind, New Mexico	94	99	98	98	10	11		
New Frontier Wind, North Dakota	288	307	95	98	16	25		
Cardinal Point Wind, Illinois [8]	404	242	97	93	42	26		
Buckthorn Wind, Texas [9]	255	168	95	94	27	12		
	4,513	4,545	86	88	305	351	175	183
Corporate [10]					94	36	(4)	(56)
Unrealized changes in fair value of commodity derivatives and emission credits					(369)	(63)		
Consolidated revenues and other income and adjusted EBITDA					**1,318**	**1,421**	**830**	**735**

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.

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

5 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, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be 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.

6 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 venture 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 $23 million for the three and nine months ended September 30, 2021, respectively, compared with $8 million and $23 million for the three and nine months ended September 30, 2020. The facility's revenues are not included in the above results.

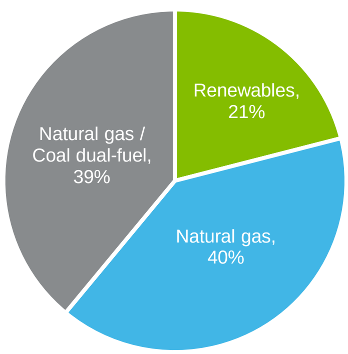
7 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations. Decommissioning of the facilities commenced in the second quarter of 2021 and decommissioning costs are expected to be lower than the Company's established decommissioning provision.

8 Cardinal Point Wind was commissioned on March 16, 2020.

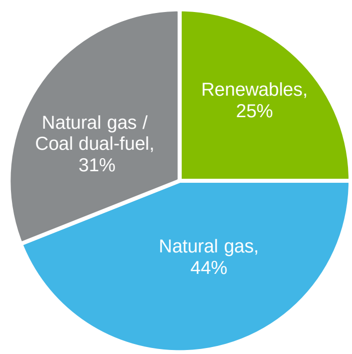
9 Buckthorn Wind was acquired on April 1, 2020.

10 Corporate revenues were offset by interplant category eliminations.

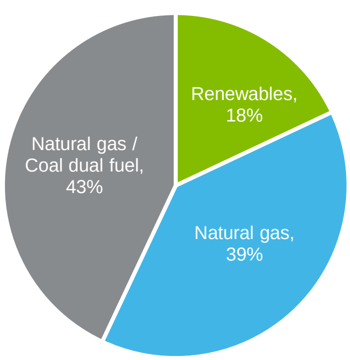
Adjusted EBITDA and revenues and other income by fuel type[1] for the nine months ended September 30



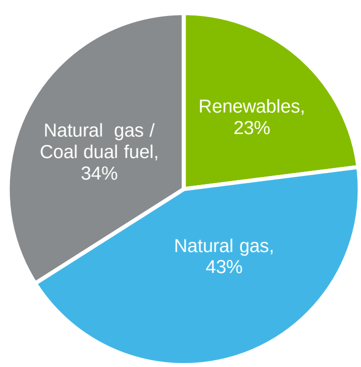
2021 Adjusted EBITDA by fuel type[1]



2020 Adjusted EBITDA by fuel type[1]



2021 Revenues and other income by fuel type[1]



2020 Revenues and other income by fuel type[1]

1 Alberta commercial adjusted EBITDA and revenues and other income are allocated to fuel source based on generation. The period-over-period increases in percentages from natural gas / coal dual-fuel are largely driven by significantly higher Alberta power prices in 2021 as compared to 2020 as well as the acceleration of off-coal compensation recognition in 2021 as a result of the repowering of Genesee 1 and 2 announced in late 2020.

Energy prices and hedged positions

Alberta portfolio metric	Unit	Three months ended September 30 2021	Three months ended September 30 2020	Nine months ended September 30 2021	Nine months ended September 30 2020	Year ended December 31, 2020
Hedged position [1]	Percentage sold forward at beginning of period (%)	69	100	33	73	72
Spot power price average	$ per megawatt hour (MWh)	100	44	100	47	47
Realized power price [2]	$ per MWh	75	59	76	58	58
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	3.32	2.17	3.14	2.03	2.16

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

2 Realized power price is the average price realized as a result of the Company's commercial contracted sales and portfolio optimization activities.

3 AECO refers to the historical virtual trading hub located in Alberta and known as the NOVA Inventory Transfer system operated by TC Energy.

Alberta commercial facilities and portfolio optimization

The Alberta spot price averaged $100 per MWh for each of the three and nine month periods ended September 30, 2021, respectively, which were significantly higher than the corresponding periods in 2020. The first and second quarters of 2021 each included one month of higher pricing as a result of cold and hot temperatures, respectively, and baseload facility outages. Each month in the third quarter of 2021 saw significantly higher pricing than 2020, primarily due to a combination of hot temperatures and facility outages as well as demand recovery. The remaining months settled at moderate pricing with stable baseload supply, but with higher monthly pricing in the 2021 months compared with 2020.

For the three and nine months ended September 30, 2021, generation and availability were lower than the comparable periods in 2020, primarily due to an ongoing unplanned outage at Genesee 2 that began in July of 2021, and a planned outage at Shepard in the second quarter of 2021, compared with no planned outage in the first nine months of 2020. In addition, Genesee 1 experienced more unplanned outages in 2021 compared with 2020 and Joffre completed planned outages in the second and third quarters of 2021 compared with a shorter planned outage in the first quarter of 2020. Generation for the three months ended September 30, 2021 was also impacted by higher CBEC dispatch, compared with the same period in 2020, to partially compensate for the unplanned outage at Genesee 2.

Revenues and other income for the three and nine months ended September 30, 2021 were higher than the comparable periods in 2020 primarily due to higher Alberta spot power prices. The PPAs for Genesee 1 and 2 expired at the end of 2020, with subsequent revenue being on a merchant or non-contracted basis which led to increased revenues in the first nine months of 2021 as compared to 2020 for Genesee 1 and 2, despite the ongoing unplanned outage at Genesee 2. These revenue increases were partially offset by lower revenues from portfolio optimization activities as a result of power and natural gas forward sales contracts settling unfavourably against higher spot prices in 2021 compared with 2020.

Adjusted EBITDA for the three and nine months ended September 30, 2021 was higher than the comparable periods in 2020 due largely to the aforementioned higher Alberta power prices in 2021 compared with 2020 and the impacts of the Genesee 1 and 2 PPA expiry, partially offset by the impacts of the lower generation volumes described above. Further offsetting these impacts were higher transmission expenses in the three and nine months ended September 30, 2021 than in the comparable periods in 2020 due to the aforementioned higher spot power prices as well as an increase in Alberta emissions pricing in 2021 and higher emissions costs at the Genesee facilities, where upon the expiration of the PPAs for Genesee 1 and 2, emissions costs are no longer passed on to the PPA Buyer.

Western Canada contracted facilities

Generation for the three and nine months ended September 30, 2021 was higher compared with the corresponding periods in 2020 primarily due to higher dispatch at Island Generation driven by the need for additional capacity during 2021 in British Columbia.

Availability for the three and nine months ended September 30, 2021 was lower than the corresponding period in 2020 primarily due to an unplanned outage at Island Generation in the second quarter of 2021, compared with minimal unplanned outages in the corresponding periods of 2020. The availability variances at Island Generation were partially offset by less frequent and shorter outages at the EnPower facilities in the nine months ended September 30, 2021, compared with the same period in 2020. Whitla Wind and Quality Wind also experienced more frequent turbine maintenance outages in the third quarter of 2021 compared with the same period in 2020.

Revenues and other income and adjusted EBITDA for the three and nine months ended September 30, 2021 were lower compared with the corresponding periods in 2020 due to the noted outage at Island Generation and lower wind resource availability. Adjusted EBITDA was also lower due to higher transmission and property tax costs at Whitla Wind.

Ontario contracted facilities

Variances for generation and availability for the three and nine months ended September 30, 2021 compared to the corresponding periods in 2020 were primarily due to activities and results at Goreway.

Goreway experienced a longer planned outage in the second quarter of 2021 compared to the same period in 2020 but also experienced a planned outage in the third quarter of 2020, with no planned outage in the same period in 2021, and fewer and shorter unplanned outages in the nine months ended September 30, 2021 compared with the same period in 2020. These outage impacts contributed to both the generation and availability variances at Goreway, with higher dispatch also contributing to the generation variances. In addition, York Energy experienced a longer planned outage in the third quarter of 2021 compared with the same period in 2020.

Revenues and other income were higher in the three and nine months ended September 30, 2021 compared with the same periods in 2020 primarily due to the aforementioned higher dispatch at Goreway, partially offset by lower wind resource availability at Port Dover and Nanticoke. Adjusted EBITDA was lower in the nine months ended September 30, 2021, compared with the same period in 2020 primarily due to Goreway experiencing higher fuel pricing in the nine months ended September 30, 2021 compared with the corresponding period in 2020 and higher costs related to the longer planned outage in the second quarter of 2021 partially offset by the aforementioned impacts of revenue and other income noted above. Lower wind resource availability at Port Dover and Nanticoke Wind further contributed to lower adjusted EBITDA for the nine months ended September 30, 2021.

U.S. contracted facilities

Availability for the three and nine months ended September 30, 2021 was lower than the comparable periods in 2020 primarily due to a longer planned outage at Decatur in 2021 compared with 2020 that occurred during the first and second quarters of each year as well as more frequent and longer unplanned outages at Decatur in the third quarter of 2021, compared with the same period in 2020. Partially offsetting the Decatur availability variance for the nine months ended September 30, 2021 compared with the same period in 2020, was a shorter planned outage at Arlington Valley in 2021 compared with 2020 and no outages at the Southport and Roxboro facilities during their final quarter of operations in the first quarter of 2021.

The aforementioned availability variances were the primary drivers of the generation variances when comparing the three and nine months ended September 30, 2021 to the same periods in 2020. In addition, for both the three and nine month periods, the retirement of the Southport and Roxboro facilities reduced generation as did lower wind resource availability at Bloom Wind and New Frontier Wind, partially offset by higher dispatch at Arlington Valley. Generation variances for the nine months ended September 30, 2021 were also driven by the commencement of operations at Cardinal Point Wind on March 16, 2020, the acquisition of Buckthorn Wind on April 1, 2020 and higher dispatch at Decatur in the first quarter of 2021 compared with 2020, despite more planned outage hours in the first quarter of 2021 compared with 2020 at that facility.

Revenues and other income for the three and nine months ended September 30, 2021 were lower than the comparable periods in 2020 primarily due to the aforementioned availability and generation variances, as well as the impacts of a stronger Canadian dollar in 2021, partially offset by higher heat rate call option (HRCO) revenues driven by the impact of higher natural gas prices on the HRCO pricing at Arlington Valley in the first six months of 2021 compared with the same period in 2020.

Adjusted EBITDA for the three months ended September 30, 2021 was lower than the comparable period in 2020 primarily due to the retirement of the Southport and Roxboro facilities effective March 31, 2021, lower Decatur margins driven by the noted unplanned outages, the impacts of a stronger Canadian dollar in 2021 and the aforementioned lower wind availability at Bloom Wind and New Frontier Wind.

Adjusted EBITDA for the nine months ended September 30, 2021 was lower than the comparable period in 2020 due to the retirement of the Southport and Roxboro facilities effective March 31, 2021, the impacts of a stronger Canadian dollar in 2021 and the aforementioned lower wind resource availability at Bloom Wind and New Frontier Wind. These unfavourable variances were partially offset by the aforementioned Arlington Valley HRCO margins as well as the acquisition of Buckthorn Wind on April 1, 2020 and the commencement of operations at Cardinal Point Wind on March 16, 2020.

Corporate

Corporate results include (i) revenues for cost recoveries and other income related to 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 higher for the three and nine months ended September 30, 2021 compared with the same periods in 2020 due to accelerated recognition of coal compensation revenue in 2021 as a result of the repowering of Genesee 1 and 2 announced in late 2020. Adjusted EBITDA for the three and nine months ended September 30, 2021, was impacted by the acceleration of coal compensation revenue as well as the reversal of a contingent consideration provision that is no longer required related to a previous acquisition, partially offset by higher incentive expenses due to larger increases in the Company's share price during the first nine months of 2021 as compared to decreases in the comparable period of 2020 as well as higher commercial project costs during 2021 as compared to 2020.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended September 30			
	2021	**2020**	**2021**	**2020**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Income before tax**	
Unrealized losses on Alberta power derivatives	(50)	(6)	(56)	(2)
Unrealized losses on U.S. power derivatives	(75)	(24)	(75)	(24)
Unrealized (losses) gains on natural gas derivatives	(53)	(31)	64	63
Unrealized losses on emission derivatives	(1)	(5)	(1)	(5)
Unrealized gains (losses) on emission credits held for trading	-	-	2	(1)
	(179)	**(66)**	**(66)**	**31**

(unaudited, $ millions)	Nine months ended September 30			
	2021	**2020**	**2021**	**2020**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Income before tax**	
Unrealized (losses) gains on Alberta power derivatives	(72)	25	(52)	(13)
Unrealized losses on U.S. power derivatives	(159)	(42)	(159)	(42)
Unrealized (losses) gains on natural gas derivatives	(128)	(34)	121	76
Unrealized losses on emission derivatives	(10)	(12)	(10)	(12)
Unrealized gains (losses) on emission credits held for trading	-	-	3	(5)
	(369)	**(63)**	**(97)**	**4**

The Company's revenues and other income and adjusted EBITDA relating to its Alberta commercial facilities and portfolio optimization and U.S. wind 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 Alberta commercial facilities and portfolio optimization and U.S. wind 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, 2021, the Alberta power portfolio recognized unrealized losses of $56 million and $52 million respectively, due to the impact of increasing forward Alberta power pricing on forward sale contracts as well as the reversal of prior period unrealized gains on positions that settled during the three and nine months ended September 30, 2021. For the comparable periods in 2020, the Alberta power portfolio recognized unrealized losses of $2 million and $13 million primarily due to the reversal of prior period unrealized gains on positions that settled during the three and nine months ended September 30, 2020.

During the three and nine months ended September 30, 2021, the U.S. power portfolio recognized unrealized losses of $75 million and $159 million respectively, as a result of the impact of increasing forward prices on the forward sale contracts associated with the Company's U.S. wind facilities. During the comparable periods in 2020, the Company recognized unrealized losses of $24 million and $42 million, also due to the impact of increasing forward power prices on forward sale contracts.

During the three and nine months ended September 30, 2021, the Company recognized unrealized gains on natural gas derivatives of $64 million and $121 million respectively, largely as a result of the impact of increasing forward natural gas pricing on the value of forward purchase contracts. During the comparable periods in 2020, the Company recognized unrealized gains of $63 million and $76 million respectively, which were also attributable to the impact of increasing forward natural gas pricing on the value of forward purchase contracts.

During the nine months ended September 30, 2021, the Company recognized unrealized losses of $10 million on emission derivatives, as a result of the impact of increasing forward prices on forward sale contracts as well as the reversal of prior period unrealized gains on positions that settled during the period. During the three months ended September 30, 2020, the Company recognized unrealized losses of $5 million on emission derivatives as a result of the reversal of prior period unrealized gains on positions that settled during the quarter. During the nine months ended September 30, 2020, the Company recognized unrealized losses of $12 million due mainly to decreasing forward prices on forward purchase contracts as well as the reversal of prior periods unrealized gains on positions that settled during that period.

During the nine months ended September 30, 2021 the Company recognized unrealized gains of $3 million on emission credits held for trading, due to the impact of increasing market prices on portfolio holdings, partially offset by the reversal of prior periods unrealized gains on emission credits sold during the period. During the comparable period in 2020 the Company recognized unrealized losses of $5 million on emission credits held for trading, due to the reversal of prior periods unrealized gains on emission credits sold during that period.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Interest on borrowings less capitalized interest	(31)	(40)	(102)	(121)
Realized losses on settlement of interest rate derivatives	(2)	(2)	(4)	(3)
Other net finance expense – interest on coal compensation from the Province of Alberta, lease liability interest, sundry interest, guarantee and other fees	-	-	(1)	3
	(33)	(42)	(107)	(121)
Unrealized gains (losses) representing changes in the fair value of interest rate derivatives	1	-	10	(2)
Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(11)	(5)	(33)	(17)
Total net finance expense	(43)	(47)	(130)	(140)
Depreciation and amortization	(133)	(115)	(402)	(356)
Gains on disposals and other transactions	31	-	30	-
Impairments, net of reversal	(8)	-	(6)	(13)
Foreign exchange (loss) gain	(7)	1	(8)	(5)
Finance expense and depreciation expense from joint venture	(4)	(4)	(9)	(23)
Income tax expense	(18)	(44)	(52)	(73)
Net loss attributable to non-controlling interests	2	2	7	4

Net finance expense

Lower net finance expense for the three months ended September 30, 2021 compared with the same period in the prior year largely reflects lower interest due to decreased loans and borrowings outstanding during the current period, lower interest on a mid-January 2020 debt renewal and higher capitalized interest as a result of Whitla Wind 2 construction and the Genesee repowering project, partially offset by higher accretion due to accelerated coal compensation. On a year-to-date basis, lower net finance expense for the nine months ended September 30, 2021 further reflects unrealized gains on non-hedge interest rate swaps driven by the impact of increasing market interest rates during 2021.

Depreciation and amortization

Depreciation and amortization for the three and nine months ended September 30, 2021 increased compared with the same period in the prior year primarily due to the accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine as a result of the late 2020 Genesee repowering announcement, offset partly by Southport and Roxboro being fully depreciated as of the end of the first quarter of 2021. Higher depreciation for the nine months ended September 30, 2021, further resulted from Cardinal Point Wind (commenced commercial operations in March 2020) and the addition of Buckthorn Wind in the second quarter of 2020.

Gains on disposals and other transactions

During the three months ended September 30, 2021, the Company recorded $16 million reflecting accrued insurance recoveries, net of related expenses incurred to date to repair Genesee 2 (see Significant Events). The Company also recorded a gain of $7 million on decommissioning of the Southport and Roxboro facilities to reflect lower decommissioning costs than what the Company previously established as provisions. The year-to-date amount further reflects other gains on disposal in the first half of 2021, 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) gain

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.

As at September 30, 2020, the Company had outstanding foreign currency non-hedge sale contracts totalling US$52 million. For the three months ended September 30, 2020, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened resulting in an unrealized gain on the foreign currency sale contracts, partially offset by realized losses on the settlement of foreign currency sale contracts in the quarter. For the nine months ended September 30, 2020, the unrealized loss is mostly attributable to outstanding foreign currency non-hedge sale contracts in the first quarter of 2020, during which the Canadian dollar weakened against the U.S. dollar.

Finance expense and depreciation expense from joint venture

Finance expense and depreciation expense from joint venture includes Capital Power's share of finance expense and depreciation expense of York Energy, which is accounted for under the equity method. Finance expense and depreciation expense from joint venture decreased by $14 million for the nine months ended September 30, 2021 compared with the same period in 2020 due to increasing interest rates during 2021 resulting in gains on the interest rate non-hedge held within the York Energy joint venture, compared with declining interest rates during 2020 resulting in higher prior period expenses.

Income tax expense

Lower income tax expense for the three and nine months ended September 30, 2021 compared with the corresponding periods in 2020 was primarily due to a $10 million deferred tax benefit from lower applicable jurisdictional tax rates recorded in the first quarter of 2021, of which no comparable tax recovery was recognized in 2020 and other rate differences associated with foreign exchange movements.

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**	
	2021	**2020**	**2021**	**2020**
Net income	38	106	156	129
Other comprehensive (loss) income:				
Net unrealized (losses) gains on derivative instruments	(60)	1	(168)	(9)
Net realized losses (gains) on derivative instruments reclassified to net income	39	(9)	127	(16)
Unrealized foreign exchange gains (losses) on the translation of foreign operations	28	(18)	10	29
Actuarial gain related to the Company's defined benefit pension plan	-	-	-	3
Total other comprehensive income (loss), net of tax	7	(26)	(31)	7
Comprehensive income	**45**	**80**	**125**	**136**

Other comprehensive (loss) income 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, 2020 to September 30, 2021 were as follows:

(unaudited, $ millions)	**As at September 30, 2021**	**As at December 31, 2020**	**Increase (decrease)**	**Primary reason for increase (decrease)**
Trade and other receivables	403	499	(96)	Decrease primarily due to a reduction in capacity payment accrued receivables and emission expense recovery resulting from the expiration of the Genesee PPA with the Balancing Pool and collection of receivables outstanding at December 2020, partially offset by accrued insurance receivables for the Genesee 2 forced outage (see Significant Events) and higher settled Alberta pool prices in September 2021 compared to December 2020.
Property, plant and equipment	6,173	6,098	75	Increase due to capital additions for Genesee Repowering, Strathmore Solar and Whitla Wind 2 as well as turbine upgrades at Decatur Energy and replacement of the Genesee 2 generator (see Significant Events). These impacts were partially offset by useful life changes (resulting from updated timelines at Genesee 1 and 2 for Repowering), the impact of increasing interest rates on decommissioning assets, foreign exchange impacts and depreciation.
Net derivative financial instruments liabilities	193	55	138	Increase primarily due to increasing forward prices on U.S. contracted wind forward sale contracts and increasing Alberta forward power prices on net forward sale contracts, partially offset by increasing forward natural gas prices on net forward purchase contracts and increasing forward interest rates on interest rate swaps.
Trade and other payables	592	470	122	Increase due to higher trading margin account payables resulting from increasing forward natural gas prices on net forward purchase contracts, higher capital and accrued liabilities related to construction activities at Whitla Wind 2, reclass of Arlington Valley long-term service agreement (LTSA) costs from deferred revenue and other liabilities, increased commodity purchases as a result of new customer contracts beginning in 2021 combined with higher settled pool prices in September 2021 compared to December 2020, partly offset by the 2020 annual emission settlement in the second quarter of 2021 compared with the fourth quarter of 2019 settled in 2020 and LLR Proceeding payables settled.
Loans and borrowings (including current portion)	2,962	3,552	(590)	Decrease primarily due to repayments of U.S. dollar bank loans, net repayments of credit facilities and allocation of income tax benefits to tax-equity investors associated with the Company's tax-equity structures.
Deferred revenue and other liabilities (including current portion)	418	412	6	Increase primarily due to spending on the Genesee Repowering project for which payments are being deferred, partially offset by the amortization of off-coal compensation.

(unaudited, $ millions)	As at September 30, 2021	As at December 31, 2020	Increase (decrease)	Primary reason for increase (decrease)
Provisions (including current portion)	434	501	(67)	Decrease mainly due to decommissioning of Southport and Roxboro facilities along with revisions to existing decommissioning provisions driven by changes in discount rates.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Nine months ended September 30		
Cash inflows (outflows)	**2021**	**2020**	**Change**
Operating activities	682	452	230
Investing activities	(367)	(283)	(84)
Financing activities	(397)	(286)	(111)

Operating activities

Cash flows from operating activities for the nine months ended September 30, 2021 increased compared with the same period in 2020 mainly due to (i) the cash flow impacts of the increases in adjusted EBITDA described in Consolidated Net Income and Results of Operations, mainly the result of higher realized Alberta power pricing offset partly by higher Alberta emissions costs including higher emissions pricing and the assumption of the obligation for Genesee 1 and Genesee 2 emissions costs in 2021, (ii) higher favourable cash impacts relating to trading margin accounts in 2021 as compared to 2020, most notably driven by the impact of increasing natural gas prices on net forward purchase contracts in 2021, and (iii) income taxes recovered in 2021 due to a loss carryback compared with income taxes paid in 2020 largely due to tax true-up payments. These increases were partially offset by (i) the timing of the 2020 annual emissions settlement which occurred during the second quarter of 2021 as compared to during the first nine months of 2020 where only the obligation for the fourth quarter of 2019 was settled, and (ii) net settlements of tranches 2 and 3 of the LLR Proceeding invoices during the first half of 2021.

Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2021 increased compared with the same period in 2020 primarily due to higher cash capital expenditures in 2021 (net of changes in non-cash investing working capital and deferred payments relating to repowering capital expenditures in 2021), partly offset by no business acquisition activity in the first nine months of 2021 as compared to the acquisition of Buckthorn Wind in the second quarter of 2020.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2021 actual	Nine months ended September 30, 2021 actual	Balance of 2021 estimated [1,2]	Actual or projected total [2]	Targeted completion
Repowering of Genesee 1 and 2	-	169	81	997	Unit 1 in 2023 and Unit 2 in 2024
Whitla Wind 2 and 3	33	143	81	257	Fourth quarter of 2021
Strathmore Solar [3]	2	32	18	57	First quarter of 2022
Enchant Solar [3]	1	6	15	119	Fourth quarter of 2022
Bear Branch Solar [4]	1	-	1	60	Fourth quarter of 2023 or first quarter of 2024
Hornet Solar [4]	1	1	2	118	Fourth quarter of 2023 or first quarter of 2024
Hunter's Cove Solar [4]	1	-	1	82	Fourth quarter of 2023 or first quarter of 2024
Commercial initiatives [5]	154	24	5	198	
Development sites and projects	24	13	-		
Subtotal growth projects		**388**	**204**		
Sustaining – plant maintenance excluding Genesee mine [6]		102			
Sustaining – Genesee mine maintenance and lands		5			
Total capital expenditures [7]		**495**			
Emission credits held for compliance		59			
Investment in C2CNT		13			
Capitalized interest		(6)			
Additions of property, plant and equipment and other assets		**561**			
Change in other non-cash investing working capital and non-current liabilities		(137)			
Purchase of property, plant and equipment and other assets, net		**424**			

1 The Company's 2021 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 have increased from the previous amounts of $53 million for Strathmore Solar and $102 million for Enchant Solar due to supply chain pressures and significant increases in transportation costs.

4 Targeted completion dates have been revised due to delays in the interconnection process.

5 Commercial initiatives include the combustion turbine upgrade project for Decatur Energy with capital expenditures incurred life-to-date to the end of September 30, 2021 of $77 million (US$58 million). The final stage of this project resulted in an additional 30 MW of generation in 2021 (an additional 60 MW of generation was completed prior to 2021). Commercial initiatives also 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 As at September 30, 2021, a total of $25 million has been accrued for insurance recoveries related to the Genesee 2 forced outage, of which $23 million relates to sustaining capital expenditures (see Significant Events).

7 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.

Financing activities

Cash flows used in financing activities were higher in the nine months ended September 30, 2021 mainly due to higher net repayments of loans and borrowings and the prior year issuance of approximately $221 million (US$157 million) in net tax equity financing related to Cardinal Point Wind. Partially offsetting these higher cash outflows were the issuance of common shares in 2021 (see Significant Events), lower common share dividends paid in 2021 as result of the reinstatement of the Company's Dividend Reinvestment Plan in the third quarter of 2020 and lower repurchases of common shares under the Company's normal course issuer bid.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at September 30, 2021			As at December 31, 2020		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
Committed credit facilities	2026	1,000			1,000		
Letters of credit outstanding			85			9	
Bankers' acceptances outstanding			-			-	
Bank loans outstanding [1]			-			193	
		1,000	85	915	1,000	202	798
Bilateral demand credit facilities	N/A	427			427		
Letters of credit outstanding			327			259	
		427	327	100	427	259	168
Demand credit facilities	N/A	25	-	25	25	-	25
		1,452	**412**	**1,040**	**1,452**	**461**	**991**

1 U.S. dollar denominated bank loans outstanding totaling nil (December 31, 2020 – US$151 million).

As at September 30, 2021, the committed credit facility utilization decreased $117 million compared with the utilization as at December 31, 2020, 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 2021, the Company amended and transitioned its existing $1 billion of committed credit facilities to SLCs and extended their maturity to July 2026 (see Significant Events).

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 July 16, 2021. 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 outlook from DBRS Limited (DBRS), which was affirmed in their latest report, published April 7, 2021. The BBB rating category assigned by DBRS is the fourth highest rating of DBRS' 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 2021 include:

(unaudited, $ millions)	Nine months ended September 30, 2021 actual	Balance of 2021 estimated	Total 2021 expected cash requirements
Repayment of debt payable [1]	326	17	343
Interest on loans and borrowings	98	14	112
Capital expenditures – sustaining	99	25	124
Capital expenditures – ongoing growth projects [2]	227	212	439
Capital expenditures – commercial initiatives	24	5	29
Common share dividends [3]	121	45	166
Preferred share dividends	38	13	51
	933	**331**	**1,264**

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 6.8% 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 from external markets when required. Under the short-form base shelf prospectus, Capital Power may raise up to $3 billion by issuing common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities. This prospectus expires in June 2022.

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

As at September 30, 2021, the Company has $412 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, 2021	**December 31, 2020**
Loans and borrowings	2,962	3,552
Lease liabilities [1]	142	149
Less cash and cash equivalents	(285)	(367)
Net debt	2,819	3,334
Share capital	3,812	3,465
Deficit and other reserves	(652)	(565)
Non-controlling interests	22	29
Total equity	3,182	2,929
Total capital	**6,001**	**6,263**

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

CONTINGENT LIABILITIES AND PROVISIONS

Refer to Contractual Obligations, Contingent Liabilities, Other Legal Matters and Provisions discussion in the Company's 2020 Integrated Annual Report for further details that supplement the recent developments discussed below.

Contingent liabilities

The Company and its subsidiaries are subject to various legal claims, including the dispute disclosed in the Significant Events section, that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial.

Other legal matters

In each of 2017 through 2021, the Government of Alberta (GoA) withheld approximately $2.7 million from the Company's annual off-coal payment, on the basis of an alleged "implied term" of the Off-Coal Agreement. Capital Power believes there was no such implied term and has therefore sued the GoA for recovery of the withheld amount and specific performance for future payments. The status of this matter remains unchanged from what has been previously disclosed in the Company's 2020 Integrated Annual Report. The Court of Appeal has scheduled the hearing for January 14, 2022. A decision will not be available until the end of the first quarter of 2022.

Line Loss Rule Proceeding

Capital Power participated in the Line Loss Rule Proceeding before the Alberta Utilities Commission (AUC) regarding loss factors that form the basis for certain transmission charges paid by Alberta generators, including Capital Power. The LLR Proceeding addressed the replacement of the non-compliant LLR as well as the resulting adjustment of line loss charges and credits for the years 2006 up to and including 2016.

Based on current AUC decisions, Capital Power incurred additional charges related to historical periods and, as such, has previously recorded $19 million pertaining to the Company's estimated net liability. The amount reflects a decrease of $1 million recorded during the first quarter of 2021 to reflect final tranche 3 invoices received during this period. The invoicing process results in gross billings to Capital Power of which those amounts not attributable to Capital Power are recoverable from the appropriate parties. Recovery of these amounts, with the exception of those related to the Sundance C PPA from the Balancing Pool, has proceeded as expected.

On January 26, 2021, the AUC rendered a decision in which it ordered the use of simple interest, aligning with the approach reflected in the AESO's issued invoices. An application seeking to rehear and overturn this decision was filed with the AUC on March 26, 2021. Capital Power actively participated in these proceedings to preserve the original finding and the AUC issued a favourable decision on June 22, 2021 denying this application. The party that sought to overturn the simple interest decision had filed an application to the Alberta Court of Appeal seeking permission to appeal the AUC decision but has since discontinued its application.

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

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

RISKS AND RISK MANAGEMENT

There have been no material changes in the nine months ended September 30, 2021 to the Company's business and operational risks as described in the Company's 2020 Integrated Annual Report. Information pertaining to climate-related risks and opportunities can be found on the Company's website within its 2020 Climate Change Disclosure Report.

The COVID-19 pandemic remains dynamic, with uncertainty around the ultimate duration and magnitude of the impact on the economy. The ultimate impact on the Company is dependent on future events that are uncertain at this time; however, the key impacts of these developments on the Company's risk exposures described in the Company's 2020 Integrated Annual Report and key strategies for mitigating those risks have not materially changed in the nine months ended September 30, 2021. The COVID-19 pandemic is ongoing to varying degrees in the regions in which the Company operates and may continue in some form for an extended period. There is no certainty to when the pandemic will be fully brought under control with many regions experiencing another "wave" of COVID-19 including increasing COVID-19 variant cases. However, vaccination efforts in North America continue to progress and government restrictions, including the use of "vaccine passports", are now largely structured to lessen the impacts on day-to-day business.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $343 million as at September 30, 2021 ($414 million as at December 31, 2020) 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 $434 million and forward contracts to sell environmental credits totaling $450 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 2020 Integrated Annual for further details that supplement the recent developments discussed below.

Canada

On December 11, 2020, the Government of Canada released its updated climate plan (the Federal Plan). The Federal Plan sets out a range of measures and proposed policies across multiple sectors that are intended to enable Canada to meet and exceed its current 2030 greenhouse gas reduction commitments under the Paris Agreement, and also set Canada on a path to achieving net-zero carbon emissions by 2050. Among other things, the Federal Plan proposes to increase the carbon price by $15 per tonne per year after 2022 until achieving a price of $170 per tonne in 2030.

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

The Federal Government also confirmed in July 2021 that the minimum price on carbon will increase by $15 per tonne each year starting in 2023 to a level of $170 per tonne in 2030, as set out in the Federal Plan, and advised that the "benchmark" stringency framework will be updated to ensure all provincial and territorial pricing systems are comparable in terms of stringency and effectiveness. Provinces and territories will continue to have the flexibility to implement the type of system that makes sense for their circumstances as long as they align with the benchmark.

Additional information or details regarding sector-specific targets or measures arising from the new targets, relative to the policies that have been outlined in the Federal Plan, have not been provided at this time. The Company will incorporate the new targets as part of its ongoing assessment of the potential impacts of Federal carbon policy for Capital Power's existing facilities and prospective interests in the Canadian market.

On September 21, 2021, the Canadian Federal Election resulted in the re-election of the Liberal Party of Canada as Government in a minority Parliament. The Liberal Party election platform indicated continuity on the aforementioned carbon policies. Capital Power will continue to engage with Federal Government officials regarding carbon policy-related matters and is participating in relevant policy development processes.

Alberta

On January 1, 2020, the Government of Alberta (GOA) replaced the Carbon Competitiveness Incentive Regulation (CCIR) with the TIER Regulation for large industrial emitters. On November 5, 2020 the Government of Alberta increased the carbon price under the TIER Regulation for the 2021 calendar year to $40 per tonne of carbon dioxide equivalent.

In March 2021, the Government of Alberta initiated a Climate Policy Engagement process through which it intends to seek input from stakeholders and industry sectors, including electricity, regarding various aspects of Alberta's carbon policy framework. Capital Power understands the process is intended to gather input that will inform Alberta's future policies and programs. The Company is participating in the process.

The Supreme Court of Canada (the Court) released its decision regarding the challenge filed by the governments of Alberta, Saskatchewan, Manitoba and Ontario regarding the constitutionality of the Greenhouse Gas Pollution Pricing Act (GGPPA). In a 6-3 decision, the majority of the Court upheld the constitutionality of the GGPPA and determined that the GGPPA "sets minimum national standards of GHG price stringency to reduce GHG emissions". The Governments of Alberta and Ontario have indicated they will be reviewing the decision in detail before determining next steps.

On June 22, 2021, the GOA started a consultation process to develop new surface water quality management frameworks for the North Saskatchewan, Battle and Upper Athabasca rivers. The water quality management frameworks establish clear regional objectives for water quality. The Company will participate in the consultation process since Genesee and Clover Bar Energy Centre are located on the North Saskatchewan River.

At midnight on December 31, 2020, the PPA Regulation in Alberta expired and on January 1, 2021, all remaining PPAs held by the Balancing Pool have reverted back to their respective generation facility owners. Dispatch and offer control of Genesee 1 and 2, previously under PPA with the Balancing Pool as the Buyer, now reside with the Company.

Ontario

Ontario's Independent Electric System Operator (IESO) is continuing work under its Market Renewal Program (MRP) which is a series of coordinated market reforms expected to result in a fundamental redesign of Ontario's electricity market. The IESO's stated goal for the MRP is to improve how electricity is priced, scheduled and procured to meet Ontario's electricity system needs. The Company is actively participating in the MRP stakeholder process and collaborating with the IESO.

On September 21, 2020, the Ontario Minister of the Environment, Conservation and Parks (MECP) announced that the federal government has accepted Ontario's Emissions Performance Standards (EPS) as an alternative to the federal carbon pricing regime. On December 16, 2020, the MECP started consultation with stakeholders, including Capital Power, about the transition of Ontario industrial facilities from the Federal Output-Based Pricing System (OBPS) to the provincial EPS. Environment and Climate Change Canada has recently announced that Ontario's EPS will be in effect for the year 2022. On May 27, 2021 MECP proposed additional amendments to the EPS to further support the transition of industry from federal OBPS to Ontario's EPS program, including the proposal that the electricity benchmark will be a 0.37 tonne of carbon dioxide equivalent per megawatt-hour (t/MWh) instead of the 0.42 t/MWh that was in effect under Ontario's previous EPS.

Until the transition is completed, York Energy, East Windsor and Goreway remain subject to the federal GGPPA and the federal carbon price of $40 per tonne in 2021. The contracts for these facilities have provisions that trigger amendments, the effect of which will enable recovery of at least some of the imposed federal carbon compliance costs. Though there is limited risk the Company may incur some of the compliance costs with this program, the Company does not believe the implementation in Ontario of a federal carbon pricing system or any potential provincial greenhouse gas system will have a material adverse effect on its financial condition and results of operations.

The Ontario Ministry of Energy, Northern Development and Mines (MENDM) announced on January 5, 2021 that the regulation requiring the release of the Long-term Energy Plan (LTEP) every three years has been revoked effective January 1, 2021. According to the MENDM notice, removal of this requirement is part of its plan to reform the province's long-term energy planning process. Development of a new framework intended to eliminate political interference, increase transparency, and augment accountability in the planning process was consulted on in the first and second quarters of 2021. No significant impact to the Company and its assets is expected.

On October 7, 2021, the IESO issued a report assessing the impacts of potentially phasing out natural gas generation by 2030, which it had initiated earlier in 2021. The IESO concluded that doing so was not feasible and would lead to blackouts and significantly higher costs associated with replacement generation and additional transmission infrastructure. In response to the report, The Honourable Todd Smith, Minister of Energy, issued a letter directing the IESO to undertake two initiatives. First, the IESO is to evaluate a moratorium on new natural gas generating stations in Ontario and to consider whether alternative sources of electricity can meet Ontario's objectives of affordability, reliability, and environmental stewardship. Second, Minister Smith asked the IESO to develop an achievable pathway to phase out natural gas generation and ultimately achieve zero-emissions in the electricity system, with consideration to a number of specific elements including the reliability of the electricity system; the cost to electricity ratepayers; the timeline on which this objective would be achievable; the possibility of maintaining existing generating facilities but replacing natural gas with green fuels such as hydrogen and renewable natural gas, or the development of utility-scale carbon capture and storage; and the role of technologies like pumped storage, battery storage combined with non-emitting resources, hydro, nuclear, and demand response to eliminate emissions in the electricity system. The IESO's report back to the Minister is required by November 2022. Capital Power will seek to participate and provide input into the IESO's evaluation.

British Columbia

In June 2021, BC Hydro published their draft Integrated Resource Plan (IRP). The draft references that BC Hydro is not currently intending to renew the long-term Electricity Purchase Agreement (EPA) for Capital Power's Island Generation facility at Campbell River on Vancouver Island, which expires in April 2022. The Company continues to believe the Island Generation facility is needed to ensure secure and reliable electricity supply for homes and businesses on Vancouver Island and in Metro Vancouver. The Company has been and will continue to be an active participant in BC Hydro's consultation process and the following regulatory process. BC Hydro will be incorporating feedback into its final IRP which is due to be filed with the BC Utilities Commission by the end of 2021. In September, BC Hydro indicated to the BC Utilities Commission that in response to issues with the submarine cable between Vancouver Island and the mainland, it would initiate further discussions with Capital Power to determine if Island Generation can provide economic backup capacity while repairs are undertaken over the next two to four years.

The current carrying amount of the property, plant and equipment of Island Generation at September 30, 2021 is $98 million.

On October 25, 2021, the Government of British Columbia released "CleanBC: Roadmap to 2030" which identified a number of measures and initiatives that British Columbia would undertake as part of a stronger and more ambitious plan and to achieve its 2030 emissions targets and net-zero emissions by 2050. Among other measures, the Government of British Columbia intends to increase the Clean Electricity Delivery Standard for the BC Hydro integrated grid to 100%, which it expects BC Hydro to meet in part by phasing out its remaining natural gas-fired facilities on the grid by 2030. While full details regarding implementation of this and other components of the plan are not known, particularly the implications if any for BC Hydro's forthcoming final IRP, this component of the Roadmap could limit the term for any re-contracting of the Island Generation facility.

United States

Following the November 3, 2020 U.S. presidential election, the Biden Administration has pursued a "whole of government" effort to address clean energy and climate change outlined via Executive Orders, including Executive Branch and Congressional efforts. Key risks will relate to how these efforts impact natural gas, while low carbon technologies and renewable energy stand to benefit with some caveats regarding new social license requirements.

In its entirety, the effort will include a broad range of regulatory and funding actions by the Executive Branch under existing statutory authority. These actions will range from new regulatory requirements under the Environmental Protection Agency's Clean Air Act authority to enhanced funding for climate mitigation at the Department of Energy to new climate and sustainability risk disclosure requirements at the Securities and Exchange Commission. Legislatively, a broad US$1.9 trillion infrastructure package is being addressed through Congressional action.

The legislative package is highly political and subject to significant negotiation before being passed by Congress and signed into law by the President. However, several risks and opportunities are embedded in these legislative proposals, best articulated in the President's American Jobs Plan. Some of the key provisions relevant to Capital Power include the following: (i) potential increases in the corporate tax rate, (ii) establishment of a national Clean Energy Standard that would set a goal of zero carbon emissions in the power sector by 2035, (iii) extension and enhancement or reform of tax credits that benefit clean energy investment and production, and (iv) billions of dollars in grants and loans towards research, development and deployment of low carbon technologies such as carbon capture, utilization and storage and Direct Air Capture.

With respect to renewable energy support whether through legislation or regulatory action, the Biden administration's priorities seek to increase pressure on the sector to increase labor standards and seek a more sustainable and U.S. manufactured/procured supply chain in the development process. In addition, a range of new Environmental Justice requirements are also possible in the clean energy sector.

On June 24, 2021, the White House announced an importation ban on silica and related goods, including polysilicon products, from China-based Hoshine Silicon Industry Limited (Hoshine) and its subsidiaries. The Withhold and Release Order, issued by Customs & Border Protection, requires immediate seizure of shipments of silica and polysilicon products produced by Hoshine or its subsidiaries, or products that incorporate these materials, at port of entry. The Company is in the process of assessing the impacts of this development to its supply chain but does not anticipate any material impacts of complying with the noted importation ban. The Company's efforts to date include assessing compliant supply chain options for future purchase commitments on U.S. projects.

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, 2021 and December 31, 2020 were as follows:

(unaudited, $ millions)		September 30, 2021		December 31, 2020	
	Fair value hierarchy level [1]	**Carrying amount**	**Fair value**	**Carrying amount**	**Fair value**
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	285	285	367	367
Trade and other receivables [2]	N/A	348	348	445	445
Government grant receivable [3]	Level 2	401	394	441	448
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See below	339	339	238	238
Fair value through other comprehensive income					
Derivative financial instruments assets – current and non-current	See below	20	20	10	10
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	592	592	470	470
Loans and borrowings [3]	Level 2	2,962	3,148	3,552	3,838
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See below	376	376	160	160
Fair value through other comprehensive income					
Derivative financial instruments liabilities – current and non-current	See below	176	176	143	143

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.

3 Includes current portion.

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2021 to the Company's risk management and hedging activities as described in the Company's 2020 Integrated Annual Report.

The derivative financial instruments assets and liabilities held at September 30, 2021 compared with December 31, 2020 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at September 30, 2021						
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Interest rate non-hedges**	**Foreign exchange cash flow-hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	5	326	15	9	-	-	355
	Level 3	-	4	-	-	-	-	4
		5	330	15	9	-	-	359
Derivative financial instruments liabilities	Level 2	(96)	(249)	(77)	-	(3)	(9)	(434)
	Level 3	-	(118)	-	-	-	-	(118)
		(96)	(367)	(77)	-	(3)	(9)	(552)
Net derivative financial instruments (liabilities) assets		**(91)**	**(37)**	**(62)**	**9**	**(3)**	**(9)**	**(193)**

(unaudited, $ millions)		As at December 31, 2020					
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Interest rate non-hedges**	**Foreign exchange cash-flow hedges**	**Total**
Derivative financial instruments assets	Level 2	2	172	8	-	-	182
	Level 3	-	66	-	-	-	66
		2	238	8	-	-	248
Derivative financial instruments liabilities	Level 2	(31)	(128)	(97)	(1)	(15)	(272)
	Level 3	-	(31)	-	-	-	(31)
		(31)	(159)	(97)	(1)	(15)	(303)
Net derivative financial instruments (liabilities) assets		**(29)**	**79**	**(89)**	**(1)**	**(15)**	**(55)**

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, 2021 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 30 2021**	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Total generation	6,103	4,975	5,630	6,445	6,327	5,472	5,562	6,437
Alberta commercial facilities[1]								
Genesee 1	824	708	616	807	739	689	792	848
Genesee 2	156	701	581	791	696	618	773	826
Genesee 3	1,009	951	904	928	1,014	926	913	1,015
Keephills 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Clover Bar Energy Centre 1, 2 and 3	235	67	23	112	98	79	196	135
Joffre	166	180	203	209	171	132	186	187
Shepard	739	379	803	839	784	770	867	660
Halkirk Wind	98	111	151	150	117	121	148	129
Clover Bar Landfill Gas	-	-	-	-	1	1	1	-
	3,227	3,097	3,281	3,836	3,620	3,336	3,876	3,800
Western Canada contracted facilities[1,2]								
Island Generation	424	114	28	4	47	-	7	8
Quality Wind	101	83	127	128	108	99	122	130
EnPower	-	7	11	8	2	3	10	10
Whitla Wind 1	156	178	235	258	170	192	238	77
	681	382	401	398	327	294	377	225
Ontario contracted facilities[2]								
York Energy	6	5	4	3	4	3	4	5
East Windsor	4	4	-	1	2	2	1	4
Goreway	453	159	234	279	329	217	143	157
Kingsbridge 1	13	20	30	36	15	21	32	34
Port Dover and Nanticoke	47	66	81	95	53	70	90	84
	523	254	349	414	403	313	270	284
U.S. contracted facilities								
Roxboro, North Carolina[3]	N/A	N/A	57	81	84	84	81	86
Southport, North Carolina[3]	N/A	N/A	60	95	100	114	105	127
Decatur Energy, Alabama	381	240	356	369	665	327	124	656
Arlington Valley, Arizona	876	461	545	644	693	404	377	912
Beaufort Solar, North Carolina	8	8	6	6	8	8	6	6
Bloom Wind, Kansas	132	177	165	179	154	212	183	197
Macho Springs Wind, New Mexico	15	41	38	30	21	43	35	29
New Frontier Wind, North Dakota	92	93	103	120	95	102	110	115
Cardinal Point Wind, Illinois	93	141	170	170	86	138	18	N/A
Buckthorn Wind, Texas	75	81	99	103	71	97	N/A	N/A
	1,672	1,242	1,599	1,797	1,977	1,529	1,039	2,128

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative 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 has 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, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be 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 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations.

(%)	Three months ended							
Facility availability	**Sep 30 2021**	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Total average facility availability	91	84	96	97	98	92	91	94
Alberta commercial facilities [1]								
Genesee 1	94	92	92	96	100	100	96	100
Genesee 2	19	100	100	98	100	97	97	100
Genesee 3	99	95	95	93	100	95	92	100
Keephills 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Clover Bar Energy Centre 1, 2 and 3	97	94	99	91	98	90	97	86
Joffre	92	95	100	99	99	100	93	89
Shepard	100	50	100	100	100	99	100	79
Halkirk Wind	96	98	98	97	96	99	98	99
Clover Bar Landfill Gas	24	-	-	-	37	48	53	-
	83	87	97	96	99	97	96	93
Western Canada contracted facilities [1, 2]								
Island Generation	96	89	100	100	100	100	100	92
Quality Wind	96	98	97	97	98	98	96	98
EnPower	100	93	89	98	100	74	86	91
Whitla Wind 1	95	98	98	99	98	97	97	97
	96	94	98	99	99	98	98	94
Ontario contracted facilities [2]								
York Energy	87	100	100	100	98	100	100	94
East Windsor	100	100	99	94	99	96	99	97
Goreway	100	89	99	95	93	96	88	88
Kingsbridge 1	99	98	99	100	98	98	99	99
Port Dover and Nanticoke	90	99	99	98	93	99	99	97
	97	93	99	96	94	97	92	91
U.S. contracted facilities								
Roxboro, North Carolina [3]	N/A	N/A	100	100	99	99	90	88
Southport, North Carolina [3]	N/A	N/A	100	99	98	100	85	96
Decatur Energy, Alabama	94	51	79	100	100	73	87	93
Arlington Valley, Arizona	100	78	99	96	99	77	66	99
Beaufort Solar, North Carolina	96	97	99	98	99	100	100	98
Bloom Wind, Kansas	90	98	95	99	95	98	99	99
Macho Springs Wind, New Mexico	97	98	98	98	97	98	99	98
New Frontier Wind, North Dakota	95	97	94	93	97	98	98	94
Cardinal Point Wind, Illinois	96	97	99	97	92	95	89	N/A
Buckthorn Wind, Texas	96	94	94	96	94	95	N/A	N/A
	96	72	90	98	98	82	83	96

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative 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 has 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, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be 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 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations.

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2021	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Revenues and other income								
Alberta commercial facilities and portfolio optimization[1]	313	314	343	245	274	241	276	284
Western Canada contracted facilities [1,2]	28	25	37	38	29	27	37	30
Ontario contracted facilities [2]	82	66	80	84	70	70	73	75
U.S. contracted facilities	101	86	118	112	133	117	101	103
Corporate [3]	32	32	30	19	13	12	11	141
Unrealized changes in fair value of commodity derivatives and emission credits	(179)	(136)	(54)	18	(66)	(32)	35	50
	377	**387**	**554**	**516**	**453**	**435**	**533**	**683**
Adjusted EBITDA								
Alberta commercial facilities and portfolio optimization[1]	132	136	165	99	131	106	132	134
Western Canada contracted facilities[1, 2]	20	18	29	31	22	21	30	25
Ontario contracted facilities [2,4]	53	49	57	61	52	56	58	55
U.S. contracted facilities	85	35	55	47	96	56	31	40
Corporate	(4)	3	(3)	(18)	(17)	(22)	(17)	98
	286	**241**	**303**	**220**	**284**	**217**	**234**	**352**

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative 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 has 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, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be 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 The reported Ontario contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture.

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 30 2021	Jun 30 2021	Mar 31 2021	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019
Revenues and other income	377	387	554	516	453	435	533	683
Adjusted EBITDA [1, 2,]	286	241	303	220	284	217	234	352
Net income	38	17	101	1	106	23	-	181
Net income attributable to shareholders of the Company	40	20	103	3	108	23	2	182
Basic earnings (loss) per share ($)	0.23	0.05	0.83	(0.09)	0.89	0.10	(0.11)	1.61
Diluted earnings (loss) per share ($)[3]	0.23	0.05	0.83	(0.09)	0.89	0.09	(0.11)	1.60
Normalized earnings per share ($) [1]	0.55	0.32	0.64	0.12	0.66	0.17	0.27	0.29
Net cash flows from operating activities	347	129	206	159	258	91	103	201
Adjusted funds from operations [1]	206	91	159	86	221	97	118	128
Adjusted funds from operations per share ($) [1]	1.78	0.83	1.49	0.81	2.10	0.92	1.12	1.22
Purchase of property, plant and equipment and other assets, net	176	151	97	65	67	105	81	221

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.

2 The reported Ontario contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture.

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

	Three months ended							
Spot price averages	Sep 30 2021	Jun 30 2021	Mar 31 2021	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019
Alberta power ($ per MWh)	100	105	95	46	44	30	67	47
Alberta natural gas (AECO) ($ per Gj)	3.32	3.03	3.07	2.52	2.17	1.90	1.99	2.32
Capital Power's Alberta portfolio average realized power price ($ per MWh)	75	75	77	56	59	53	62	57

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, 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 EBTIDA 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 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 emissions 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 Whitla Wind 1 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.

For the quarter ended September 30, 2020, the Company recorded net income attributable to shareholders of $108 million compared to net loss attributable to shareholders of $226 million for the quarter ended September 30, 2019. The increase in net income in the third quarter of 2020 was largely due to the pre-tax impairment of $401 million on Keephills 3 recorded upon classification as an asset held for sale in 2019. Further increases in net income in the third quarter of 2020 were driven partly by higher margins earned on Alberta commercial power and natural gas portfolio optimization and higher unrealized gains on commodity derivatives and emission credits, most notably due to the impact of increasing forward prices on natural gas forward purchase contracts during the third quarter of 2020. Higher adjusted EBITDA also resulted from the acquisition of Buckthorn Wind in the second quarter of 2020, and commencement of operations of Whitla Wind 1 late in the fourth quarter of 2019 and Cardinal Point Wind late in the first quarter of 2020. These factors were partially offset by lower adjusted EBITDA at Arlington Valley due to the revised tolling agreement in 2020 and higher net finance expense related to the noted asset additions. In addition, income tax expense in the third quarter of 2020 of $44 million compared to income tax recovery of $66 million for the third quarter of 2019 was primarily due to the recognition of a deferred tax recovery on the impairment of Keephills 3 in 2019.

For the quarter ended June 30, 2020, the Company recorded net income attributable to shareholders of $23 million compared to net income attributable to shareholders of $108 million for the quarter ended June 30, 2019. Decreases in net income in the second quarter of 2020 were driven partly by unrealized losses on commodity derivatives and emission credits of $9 million in the second quarter of 2020 compared with unrealized gains of $48 million in the second quarter of 2019. This was most notably due to unrealized losses in the second quarter of 2020 due to the reversal of prior period unrealized gains for trades settled in the period as compared to unrealized gains in the comparative period of 2019. The prior period gains were largely the result of increasing Alberta power prices on Alberta power forward purchase contracts and the impact of decreasing forward prices on forward sale contracts for the Company's U.S. wind facilities. Higher net finance expense in the second quarter of 2020 also contributed to lower net income and was due to financing related to the acquisitions of Buckthorn Wind and Goreway in the second quarters of 2020 and 2019, respectively, and tax equity financing related to Cardinal Point Wind that commenced commercial operations in the first quarter of 2020. In addition, the second quarter of 2020 had higher income tax expense mainly due to a decrease in the Alberta corporate income tax rate that resulted in a deferred income tax recovery of $51 million in the second quarter of 2019, of which there is no comparable tax recovery recognized in the second quarter of 2020. Partially offsetting these decreases was higher adjusted EBITDA, mainly from the acquisitions of Goreway in the second quarter of 2019 and Buckthorn Wind in the second quarter of 2020, and commencement of operations of Whitla Wind 1 in the fourth quarter of 2019 and Cardinal Point Wind late in the first quarter of 2020.

For the quarter ended March 31, 2020, the Company recorded net income attributable to shareholders of $2 million compared to net income attributable to shareholders of $61 million for the quarter ended March 31, 2019. Decreases in net income in the first quarter of 2020 were driven partly by unrealized losses on commodity derivatives and emission credits being $52 million higher than in the first quarter of 2019. This was most notably due to unrealized losses in the first quarter of 2020 due to the reversal of prior period unrealized gains for trades settled in the period as compared to unrealized gains in the comparative period of 2019 most notably on the reversal of prior period unrealized losses on natural gas derivatives settled during the three months ended March 31, 2019. In addition, the first quarter of 2020 had higher depreciation and amortization primarily due to the acquisition of Goreway in the second quarter of 2019 and Whitla Wind 1 commencing commercial operations in the fourth quarter of 2019 as well as higher impairments related to the discontinuation of the Genesee 4 and 5 project recorded in the quarter. Partially offsetting these decreases was higher adjusted EBITDA, mainly from the acquisition of Goreway in the second quarter of 2019 and commencement of operations of Whitla Wind 1 in the fourth quarter of 2019 and lower income tax expense primarily due to lower consolidated income before tax.

For the quarter ended December 31, 2019, the Company recorded net income attributable to shareholders of $182 million compared to net income attributable to shareholders $138 million for the quarter ended December 31, 2018. Gains in the fourth quarter of 2019 related to the Genesee 3 and Keephills 3 swap transaction were largely offset by the gain on disposal of the Company's minority owned interest in K2 Wind during the fourth quarter of 2018. Increases in net income in the fourth quarter of 2019 were driven partly by unrealized gains on commodity derivatives and emission credits being $81 million higher than in the comparable 2018 period, most notably related to the impact of decreasing forward prices on forward sale contracts for the Company's U.S. wind facilities in the fourth quarter of 2019. In addition, adjusted EBITDA was higher as a result of the 2019 addition of Goreway and the acquisition of Arlington Valley and commercial operation of New Frontier Wind in the fourth quarter of 2018 as well as higher Alberta commercial EBITDA on higher realized pricing. Partially offsetting these increases was a corresponding increase in depreciation driven by the noted asset additions. Further offsetting the increases in net income were higher tax expenses in the fourth quarter of 2019 primarily due to recognition of deferred income tax expense on the one-time adjustment to accelerate the recognition of deferred government grant revenue upon close of the Genesee 3 and Keephills 3 swap transaction, partially offset by the reversal of deferred income tax expense on the disposal of Keephills 3.

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 30 2021	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**
Share price ($/common share)								
High	45.04	42.28	38.34	36.47	30.28	29.92	38.88	35.09
Low	39.99	36.22	33.31	29.13	26.57	23.24	20.23	30.13
Close	42.71	40.95	36.40	34.98	29.39	27.98	27.15	34.39
Volume of shares traded (millions)	13.4	21.3	22.9	20.2	21.6	29.5	31.8	21.3

Outstanding share and partnership unit data

As at October 22, 2021, the Company had 115.744 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), 8 million Cumulative Minimum Rate Reset Preference Shares (Series 7), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 9), 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 as at October 22, 2021 were 117.928 million. The outstanding special limited voting share is held by EPCOR.

As at October 22, 2021, CPLP had 24.040 million general partnership units outstanding and 89.473 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, 2021 and 2020

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2021 and 2020

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Revenues	$ 325	$ 421	$ 1,153	$ 1,322
Other income	52	32	165	99
Energy purchases and fuel	(58)	(41)	(274)	(376)
Gross margin	319	412	1,044	1,045
Other raw materials and operating charges	(32)	(34)	(114)	(120)
Staff costs and employee benefits expense	(44)	(45)	(135)	(127)
Depreciation and amortization	(133)	(115)	(402)	(356)
Impairments net of reversal	(8)	-	(6)	(13)
Other administrative expense	(28)	(24)	(79)	(77)
Foreign exchange (loss) gain	(7)	1	(8)	(5)
Operating income	67	195	300	347
Gains on disposals and other transactions (note 3)	31	-	30	-
Net finance expense	(43)	(47)	(130)	(140)
Income (loss) from joint venture	1	2	8	(5)
Income before tax	56	150	208	202
Income tax expense (note 4)	(18)	(44)	(52)	(73)
Net income	$ 38	$ 106	$ 156	$ 129
Attributable to:				
Non-controlling interests	$ (2)	$ (2)	$ (7)	$ (4)
Shareholders of the Company	$ 40	$ 108	$ 163	$ 133

Earnings per share (attributable to common shareholders of the Company):

Basic (note 5)	$ 0.23	$ 0.89	$ 1.10	$ 0.87
Diluted (note 5)	$ 0.23	$ 0.89	$ 1.09	$ 0.87

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, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Net income	$ 38	$ 106	$ 156	$ 129
Other comprehensive (loss) income:				
Items that will not be reclassified subsequently to net income:				
Defined benefit plans:				
Actuarial gains[1]	-	-	-	3
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized (losses) gains on derivative instruments[2]	(60)	1	(168)	(9)
Reclassification of losses (gains) on derivative instruments to income for the period[3]	39	(9)	127	(16)
Net investment in foreign subsidiaries:				
Unrealized gains (losses) [4]	28	(18)	10	29
Total items that are or may be reclassified subsequently to net income, net of tax	7	(26)	(31)	4
Total other comprehensive income (loss), net of tax	7	(26)	(31)	7
Total comprehensive income	$ 45	$ 80	$ 125	$ 136
Attributable to:				
Non-controlling interests	$ (2)	$ (2)	$ (7)	$ (4)
Shareholders of the Company	$ 47	$ 82	$ 132	$ 140

[1] For the three and nine months ended September 30, 2021, net of income tax expense of nil. For the three and nine months ended September 30, 2020, net of income tax expense of nil and $1, respectively.

[2] For the three and nine months ended September 30, 2021, net of income tax recoveries of $20 and $53, respectively. For the three and nine months ended September 30, 2020, net of income tax expense of $2 and income tax recovery of $1, respectively.

[3] For the three and nine months ended September 30, 2021, net of reclassification of income tax recoveries of $12 and $39, respectively. For the three and nine months ended September 30, 2020, net of reclassification of income tax expense of $3 and $6, respectively.

[4] For the three and nine months ended September 30, 2021, net of income tax expense of nil. For the three and nine months ended September 30, 2020, net of income tax expense of $1 and income tax recovery of $1, respectively.

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, 2021	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 285	$ 367
Trade and other receivables	403	499
Inventories	211	220
Derivative financial instruments assets (note 6)	95	71
	994	1,157
Non-current assets:		
Other assets	42	37
Derivative financial instruments assets (note 6)	264	177
Government grant receivable	346	387
Deferred tax assets	23	19
Equity-accounted investments	147	134
Right-of-use assets	119	129
Intangible assets and goodwill	771	773
Property, plant and equipment	6,173	6,098
Total assets	$ 8,879	$ 8,911
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 592	$ 470
Derivative financial instruments liabilities (note 6)	253	91
Loans and borrowings (note 7)	125	417
Deferred revenue and other liabilities	144	135
Provisions	44	37
	1,158	1,150
Non-current liabilities:		
Derivative financial instruments liabilities (note 6)	299	212
Loans and borrowings (note 7)	2,837	3,135
Lease liabilities	136	143
Deferred revenue and other liabilities	274	277
Deferred tax liabilities	603	601
Provisions	390	464
	4,539	4,832
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 8)	3,812	3,465
Deficit	(529)	(474)
Other reserves	(123)	(91)
Deficit and other reserves	(652)	(565)
	3,160	2,900
Non-controlling interests	22	29
Total equity	3,182	2,929
Total liabilities and equity	$ 8,879	$ 8,911

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 8)	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	-	(221)	-	-	-	-	(221)	-	(221)
Reclassification of losses to net income	-	166	-	-	-	-	166	-	166
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 8)	-	-	-	-	-	(177)	(177)	-	(177)
Preferred share dividends (note 8)	-	-	-	-	-	(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 Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital (note 8)	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, 2020	$ 3,441	$ (10)	$ (16)	$ (15)	$ 11	$ (347)	$ 3,064	$ 37	$ 3,101
Net income (loss)	-	-	-	-	-	133	133	(4)	129
Other comprehensive (loss) income:									
Defined benefit plan actuarial gain	-	-	-	4	-	-	4	-	4
Cash flow derivative hedge losses	-	(10)	-	-	-	-	(10)	-	(10)
Reclassification of gains to net income	-	(22)	-	-	-	-	(22)	-	(22)
Unrealized gains on foreign currency translation	-	-	28	-	-	-	28	-	28
Tax on items recognized directly in equity	-	7	1	(1)	-	-	7	-	7
Other comprehensive (loss) income	$ -	$ (25)	$ 29	$ 3	$ -	$ -	$ 7	$ -	$ 7
Total comprehensive (loss) income	-	(25)	29	3	-	133	140	(4)	136
Distributions to non-controlling interests	-	-	-	-	-	-	-	(2)	(2)
Common share dividends (note 8)	-	-	-	-	-	(155)	(155)	-	(155)
Preferred share dividends (note 8)	-	-	-	-	-	(39)	(39)	-	(39)
Tax on preferred share dividends	-	-	-	-	-	(2)	(2)	-	(2)
Common shares purchased	(10)	-	-	-	-	-	(10)	-	(10)
Share options exercised	7	-	-	-	-	-	7	-	7
Equity as at September 30, 2020	$ 3,438	$ (35)	$ 13	$ (12)	$ 11	$ (410)	$ 3,005	$ 31	$ 3,036

[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, 2021	2020
Cash flows from operating activities:		
Net income	$ 156	$ 129
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Impairments, net of reversal	6	13
Depreciation and amortization	402	356
Net finance expense	130	140
Fair value changes on commodity derivative instruments and emission credits held for trading	97	(4)
Foreign exchange losses	8	5
Income tax expense	52	73
(Income) loss from joint venture	(8)	5
Recognition of government grant deferred revenue	(94)	(32)
Tax equity attributes	(66)	(63)
Other items	8	8
Change in fair value of derivative instruments reflected as cash settlement	(17)	(26)
Distributions received from joint venture	8	8
Interest paid	(98)	(101)
Income taxes recovered (paid)	13	(38)
Other cash items	(20)	(33)
Change in non-cash operating working capital	105	12
Net cash flows from operating activities	682	452
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets, net[1]	(424)	(253)
Business acquisition, net of acquired cash	-	(79)
Government grant received	50	50
Other cash flows from (used in) investing activities	7	(1)
Net cash flows used in investing activities	(367)	(283)
Cash flows used in financing activities:		
Proceeds from issue of loans and borrowings	-	228
Repayment of loans and borrowings	(518)	(286)
Issue costs on loans and borrowings	(1)	(7)
Repayment of lease liabilities	(4)	(5)
Issue of shares	288	-
Share issue costs	(12)	-
Proceeds from exercise of share options	19	7
Common shares purchased (note 8)	-	(10)
Dividends paid (note 8)	(159)	(190)
Capitalized interest paid	(6)	(4)
Distributions to non-controlling interests	-	(2)
Income taxes paid on preferred share dividends	(4)	(17)
Net cash flows used in financing activities	(397)	(286)
Foreign exchange loss on cash held in a foreign currency	-	(1)
Net decrease in cash and cash equivalents	(82)	(118)
Cash and cash equivalents at beginning of period	367	248
Cash and cash equivalents at end of period	$ 285	$ 130

[1] Reflects total additions for the nine months ended September 30, 2021, reduced by $137 million for changes in non-cash investing working capital and other non-current liabilities (2020 – increased by $17 million), to arrive at cash additions of property, plant and equipment and other assets.

See accompanying notes to the condensed interim consolidated financial statements

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

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 2020 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 26, 2021.

3. Gains on disposals and other transactions:

	Three months ended September 30, 2021	Nine months ended September 30, 2021
Insurance recoveries net of related expenses [1]	$ 16	$ 16
Gains on decommissioning of facilities [2]	7	8
Other gains on disposals	8	6
Total gains on disposals and other transactions	$ 31	$ 30

[1] In July 2021, Genesee 2 experienced a forced outage due to a generator failure. Genesee 2 is undergoing repairs and expected to return to service at the end of November 2021. The amount reflected here for the three and nine months ended September 30, 2021 includes total accrued insurance recoveries to date of $25 million less $3 million of expenses incurred to date related to the outage and a loss on disposal of the damaged equipment of $6 million written off from property, plant and equipment. Accrued insurance recoveries reflect both the expensed costs noted above and capitalized costs incurred to date to repair Genesee 2 (recorded within property, plant and equipment), net of the deductible amount under the insurance contract.

[2] At the end of the first quarter of 2021, the Southport and Roxboro facilities ceased operations and have since commenced decommissioning. The gains above reflect lower decommissioning costs than what the Company previously established as provisions.

(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, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Income before tax	$ 56	$ 150	$ 208	$ 202
Income tax at the statutory rate of 23%[1] (2020 – 25%)	13	38	48	51
Increase (decrease) resulting from:				
Non-deductible amounts	2	-	6	2
Amounts attributable to non-controlling interests and tax-equity interests	9	6	17	16
Change in unrecognized tax benefits	(4)	(2)	(4)	-
Statutory and other rate differences	(3)	-	(17)	1
Other	1	2	2	3
Income tax expense	$ 18	$ 44	$ 52	$ 73

[1] On June 28, 2019, as a result of the Alberta Government's Bill 3 - Job Creation Tax Cut Act, the Alberta corporate income tax rate was reduced from 12% to 8% over 4 years. On June 29, 2020, the Alberta Government announced, as part of Alberta's Recovery Plan, the Job Creation Tax Cut Act will be accelerated to reduce the Alberta corporate income tax rate from 10% to 8% effective July 1, 2020. The Alberta corporate tax rate reduction to 8% was considered substantively enacted as at October 20, 2020. Accordingly, the 2020 statutory rate was still 25% as at September 30, 2020 and the 2021 statutory rate is 23%.

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, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Income for the period attributable to shareholders	$ 40	$ 108	$ 163	$ 133
Preferred share dividends[1]	(13)	(14)	(41)	(41)
Earnings available to common shareholders	$ 27	$ 94	$ 122	$ 92
Weighted average number of common shares	115,492,560	105,078,412	110,712,898	105,181,400
Basic earnings per share	$ 0.23	$ 0.89	$ 1.10	$ 0.87
Weighted average number of common shares	115,492,560	105,078,412	110,712,898	105,181,400
Effect of dilutive share purchase options	832,799	448,173	761,455	516,786
Diluted weighted average number of common shares	116,325,359	105,526,585	111,474,353	105,698,186
Diluted earnings per share	$ 0.23	$ 0.89	$ 1.09	$ 0.87

[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, 2021						
	Energy and emission allowances		Interest rate		Foreign exchange		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:							
Current	$ 4	$ 82	$ -	$ 9	$ -	$ -	$ 95
Non-current	1	248	15	-	-	-	264
Derivative instruments liabilities:							
Current	(70)	(144)	(27)	-	(3)	(9)	(253)
Non-current	(26)	(223)	(50)	-	-	-	(299)
Net fair value	$ (91)	$ (37)	$ (62)	$ 9	$ (3)	$ (9)	$ (193)
Net notional buys (sells) (millions):							
Megawatt hours of electricity	(6)	(22)					
Gigajoules of natural gas purchased [1]		125					
Gigajoules of natural gas basis swaps[1]		127					
Number of renewable energy credits		(4)					
Interest rate swaps			$1,431	$ 60			
Forward currency buys (sells) (U.S. dollars)					$ 17	$ (199)	
Range of remaining contract terms in years	0.1 to 4.3	0.1 to 16.3	0.2 to 5.3	1.7 to 2.2	0.1 to 0.2	0.1	

[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, 2020					
	Energy and emission allowances		Interest rate		Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	Total
Derivative instruments assets:						
Current	$ 1	$ 65	$ 5	$ -	$ -	$ 71
Non-current	1	173	3	-	-	177
Derivative instruments liabilities:						
Current	(13)	(39)	(23)	(1)	(15)	(91)
Non-current	(18)	(120)	(74)	-	-	(212)
Net fair value	$ (29)	$ 79	$ (89)	$ (1)	$ (15)	$ (55)
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(5)	(20)				
Gigajoules of natural gas purchased[2]		195				
Gigajoules of natural gas basis swaps[2]		197				
Metric tonnes of emission allowances		1				
Number of renewable energy credits		(6)				
Interest rate swaps			$ 1,001	$ 260		
Interest rate swaps (U.S. dollars)			$ 180			
Forward currency buys (U.S. dollars)					$ 94	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 17.0	0.5 to 6.1	0.9 to 1.7	0.3 to 1.0	

[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 2020 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 (loss) and net income are:

	Three months ended September 30, 2021		Three months ended September 30, 2020	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized (losses) gains	Realized gains (losses)
Energy cash flow hedges	$ (41)	$ (49)	$ (10)	$ 14
Energy and emission allowances non-hedges	(68)	3	32	18
Interest rate cash flow hedges	5	(2)	3	(2)
Interest rate non-hedges	1	-	-	-
Foreign exchange cash flow hedges	7	-	(2)	-
Foreign exchange non-hedges	(3)	(4)	2	-

(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, 2021		Nine months ended September 30, 2020	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (94)	$ (160)	$ 20	$ 26
Energy and emission allowances non-hedges	(100)	(5)	9	39
Interest rate cash flow hedges[3]	27	(4)	(43)	(4)
Interest rate non-hedges	10	-	(2)	1
Foreign exchange cash flow hedges	12	-	(9)	-
Foreign exchange non-hedges	(9)	1	(1)	(2)

[3] Includes the settlement of interest rate cash flow hedges of US$180 million in June 2021 for a gain of $14 million of which $12 million was deferred within accumulated other comprehensive loss to be reclassified to net income in future periods within the associated net finance expense pertaining to the hedged note offering.

Realized and unrealized gains and losses relate only to derivative financial instruments. 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, 2021 and 2020:

	Three months ended September 30,		Nine months ended September 30,	
	2021	2020	2021	2020
Revenues	$ (305)	$ (30)	$ (739)	$ 11
Energy purchases and fuel	191	94	474	63
Foreign exchange (loss) gain	(7)	2	(8)	(3)
Net finance expense	(1)	(2)	6	(5)

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, 2021, nil and $2 million of gains, respectively, were realized within net finance expense pertaining to the ineffective portion of hedging derivatives (three and nine months ended September 30, 2020 – nil).

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, 2021
Within one year	$ (81)
Between one and five years	(22)
After five years	7
	$ (96)

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

7. Loans and borrowings:

US$150 million private placement of senior notes

On July 20, 2021, the Company executed a US$150 million private placement of senior notes. The 12-year senior notes will bear a coupon rate of 3.24% and mature on October 28, 2033. Subject to satisfying customary closing conditions, the transaction is expected to fund on October 28, 2021.

Sustainability-linked credit facilities

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

8. Share capital:

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2021		2020		2021		2020	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[1]	$ 0.5475	$ 63	$ 0.5125	$ 54	$ 1.5725	$ 177	$ 1.4725	$155
Preference								
Series 1	0.1638	1	0.1913	1	0.4914	3	0.5738	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	9
Series 7	0.3750	3	0.3750	3	1.1250	9	1.1250	9
Series 9	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 July 29, 2021, the Company's Board of Directors approved an increase of 6.8% to $2.19 in the annual dividend per common share effective for the third quarter of 2021.

	Dividends paid[3]							
	For the three months ended September 30,				For the nine months ended September 30,			
	2021		2020		2021		2020	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[2]	$ 0.5125	$ 59	$ 0.4800	$ 50	$ 1.5375	$ 168	$ 1.4400	$151

[2] 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.

For the three and nine months ended September 30, 2020, all common dividends were paid in cash. The Company reinstated its dividend reinvestment plan for its common shares effective for the September 30, 2020 dividend (paid in the fourth quarter of 2020).

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

During the three and nine months ended September 30, 2021, the Company did not purchase and cancel any of its outstanding common shares under its Toronto Stock Exchange approved normal course issuer bid (three and nine months ended September 30, 2020 – nil and 461,832 common shares at an average exercise price of $22.67 per share for $10 million, respectively).

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

8. Share capital, continued:

In June 2021, the Company completed a public offering of 7,480,750 common shares (inclusive of the full exercise of a 975,750 common share over-allotment option) at an issue price of $38.45 per common share for total gross proceeds of approximately $288 million less issue costs of $12 million.

9. 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 2020 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 2020 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, 2021		December 31, 2020	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets[1]					
Government grant receivable	Level 2	$ 401	$ 394	$ 441	$ 448
Financial liabilities[1]					
Loans and borrowings	Level 2	$ 2,962	$ 3,148	$ 3,552	$ 3,838

[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 as at December 31, 2020.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2020 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. The transfers between levels in the fair value hierarchy for the three and nine months ended September 30, 2021 and the year ended December 31, 2020 are disclosed below within the continuity of Level 3 balances.

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

9. Financial instruments, continued:

Fair value hierarchy, continued

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 2020 annual consolidated financial statements.

	September 30, 2021			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 355	$ 4	$ 359
Derivative financial instruments liabilities	-	(434)	(118)	(552)

	December 31, 2020			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 182	$ 66	$ 248
Derivative financial instruments liabilities	-	(272)	(31)	(303)

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, the 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 5 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.

In addition, as at September 30, 2021 and December 31, 2020, the Company holds contracts for the sale of renewable energy credits (RECs) 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, 2021	December 31, 2020
REC pricing (per certificate) – Solar	$26.42 to $361.20	$206.86 to $384.76
REC pricing (per certificate) – Wind	$2.50 to $5.08	$1.99
Forward power pricing (per MWh) - Wind	$20.05 to $91.39	$19.32 to $79.17
Monthly generation (MWh) – Bloom Wind	49,721 to 71,629	51,100 to 70,160
Monthly generation (MWh) – Buckthorn Wind	11,365 to 21,736	11,365 to 21,736

Valuation process applied to Level 3

The valuation models used to calculate the fair values of the derivative financial instruments 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.

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

9. Financial instruments, continued:

Fair value hierarchy, continued

The table below presents the impact to fair value of Level 3 derivative instruments based on reasonably possible alternative assumptions:

	September 30, 2021	December 31, 2020
REC pricing – Solar[2]	$ 1	$ 1
REC pricing – Wind[3]	4	4
Forward power pricing – Wind[3]	14	15
Generation – Wind[4]	14	7

[2] Reflects the increase or decrease to fair value calculated using a $10 per unit decrease or increase in the input.

[3] Reflects the increase or decrease to fair value calculated using a $1 per unit decrease or increase in the input.

[4] Reflects the increase or decrease to fair value calculated using a 10% decrease or increase in the input.

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, 2021	December 31, 2020
As at January 1[5]	$ 35	$ 41
Acquired with Buckthorn Wind	-	44
Unrealized and realized losses included in net income[6]	(144)	(41)
Settlements[7]	(3)	(4)
Transfers[8]	-	(3)
Foreign exchange losses	(2)	(2)
As at end of period	$ (114)	$ 35
Total unrealized and realized losses for the period included in net income[6]	$ (144)	$ (41)

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

[6] Recorded in revenues.

[7] Relates to settlement of financial derivative instruments.

[8] Relates to transfers from Level 3 to Level 2 when pricing inputs became readily observable.

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)

10. Commitments, contingencies and other:

Island Generation Electricity Purchase Agreement

In June 2021, BC Hydro published their Draft 2021 Integrated Resource Plan (Draft IRP) which noted that they are not currently intending to renew the long-term Electricity Purchase Agreement (EPA) for the Company's Island Generation facility at Campbell River on Vancouver Island, which expires in April 2022. Despite the Draft IRP proposing to not seek renewal of the EPA, it did not include any technical assessment or contingency analysis to support the basis for BC Hydro's position that Island Generation is not required for system reliability post-April 2022, or to demonstrate that other measures will be available and effective in ensuring reliability in the absence of Island Generation post-April 2022. The Company believes that the Island Generation facility will continue to be required to ensure secure and reliable electricity supply for homes and businesses on Vancouver Island and in Metro Vancouver.

In July, 2021, the Company responded to BC Hydro's request for feedback on the Draft IRP and will continue to actively participate in BC Hydro's consultation process and the following regulatory process. BC Hydro will be incorporating feedback into its final Integrated Resource Plan which is due to be filed with the British Columbia Utilities Commission by the end of 2021.

The current carrying amount of the property, plant and equipment of Island Generation at September 30, 2021 is $98 million.

Buckthorn Wind settlement dispute

Following the severe weather events during the February 9 to 20, 2021 period, the Company settled the offtake and commodity swaps for Buckthorn Wind for the noted time period based on the pricing dictated in the respective agreements. However, Buckthorn Wind's counterparty is contesting the settlement, arguing that settlement should have been based upon a different reference price. Historically these two prices have been similar, but as a result of the recent extreme weather, the Company became aware of a divergence in these prices during scarcity events. Both parties have invoked dispute-resolution procedures and the Company has initiated litigation. Based on the contract terms of the offtake and commodity swaps, the Company considers the probability of ultimate settlement using the reference price advocated by the counterparty as being unlikely. In the event that the dispute is resolved unfavorably to the Company, the net exposure to the Company's revenues would be a reduction of up to approximately $18 million (US$15 million).

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 and Texas), 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, 2021				Three months ended September 30, 2020			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external[1]	$ 396	$ (71)	$ -	$ 325	$ 360	$ 61	$ -	$ 421
Revenues – inter-area	5	-	(5)	-	(28)	(6)	34	-
Other income	34	18	-	52	12	20	-	32
Total revenues and other income	$ 435	$ (53)	$ (5)	$ 377	$ 344	$ 75	$ 34	$ 453

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

11. Segment information, continued:

	Nine months ended September 30, 2021				Nine months ended September 30, 2020			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external[1]	$ 1,240	$ (87)	$ -	$1,153	$ 1,109	$ 213	$ -	$1,322
Revenues – inter-area	18	-	(18)	-	(21)	(9)	30	-
Other income	100	65	-	165	37	62	-	99
Total revenues and other income	$ 1,358	$ (22)	$ (18)	$1,318	$ 1,125	$ 266	$ 30	$1,421

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

	As at September 30, 2021			As at December 31, 2020		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 4,549	$ 1,624	$ 6,173	$ 4,417	$ 1,681	$ 6,098
Right-of-use assets	54	65	119	60	69	129
Intangible assets and goodwill	651	120	771	637	136	773
Other assets	42	-	42	37	-	37
	$ 5,296	$ 1,809	$ 7,105	$ 5,151	$ 1,886	$ 7,037

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, 2021						
	Alberta Commercial[3]	Western Canada Contracted[4]	Ontario Contracted[4]	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 398	$ 19	$ 81	$ 13	$ 511	$ (191)	$ 320
Emission credit revenues	4	-	-	-	4	1	5
Total revenues[2]	$ 402	$ 19	$ 81	$ 13	$ 515	(190)	$ 325

	Nine months ended September 30, 2021						
	Alberta Commercial[3]	Western Canada Contracted[4]	Ontario Contracted[4]	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,204	$ 63	$ 221	$ 133	$ 1,621	$ (484)	$ 1,137
Emission credit revenues	17	-	-	2	19	(3)	16
Total revenues[2]	$ 1,221	$ 63	$ 221	$ 135	$ 1,640	(487)	$ 1,153

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

11. Segment information, continued:

	Three months ended September 30, 2020						
	Alberta Commercial	Western Canada Contracted[4]	Ontario Contracted[4]	U.S. Contracted	Total from contracts with customers	Other sources[3]	Total
Energy revenues	$ 133	$ 22	$ 69	$ 33	$ 257	$ 156	$ 413
Emission credit revenues	6	-	-	3	9	(1)	8
Total revenues[2]	$ 139	$ 22	$ 69	$ 36	$ 266	$ 155	$ 421

	Nine months ended September 30, 2020						
	Alberta Commercial	Western Canada Contracted[4]	Ontario Contracted[4]	U.S. Contracted	Total from contracts with customers	Other sources[3]	Total
Energy revenues	$ 426	$ 68	$ 209	$ 140	$ 843	$ 458	$ 1,301
Emission credit revenues	20	-	-	7	27	(6)	21
Total revenues[2]	$ 446	$ 68	$ 209	$ 147	$ 870	$ 452	$ 1,322

[2] Included within trade and other receivables, as at September 30, 2021, were amounts related to contracts with customers of $195 million (2020 - $112 million).

[3] The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Comparative periods reflect energy sold on a contracted basis and accounted for under IFRS 16 – *Leases* which was therefore excluded from the scope of IFRS 15 – *Revenue from Contracts with Customers* and disclosed as revenues from other sources.

[4] 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, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be 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.

12. Comparative figures:

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