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Capital Power announces second quarter 2025 results

The Company expands and enhances its US flexible generation portfolio with its largest acquisition to date

EDMONTON, Alberta – July 30, 2025 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended June 30, 2025.

Highlights

- Completed previously announced acquisition of the Hummel and Rolling Hills facilities in the PJM[1] market for ~$3.0 billion[2] (US $2.2 billion), adding ~2.2 GW of capacity to its U.S. flexible generation[3] portfolio, the largest acquisition in the Company's history
- Increased its annual common share dividend, for the 12th consecutive year, by 6%
- Executed a ~$1.7 billion[4] (US $1.2 billion) inaugural US private offering of senior notes and obtained a third credit rating with Fitch assigning a BBB- rating
- Raised $667 million of equity capital consisting of an upsized bought deal offering of common shares, for total gross proceeds of $517 million, and a concurrent private placement of $150 million with Alberta Investment Management Corporation (AIMCo)
- Reached commercial operation of the 40MW uprate at Goreway and continued to advance four other long-term contracted projects in Ontario with 310MW of total capacity
- Started construction on two additional solar projects in North Carolina, with commercial operation expected between Q4 2026 and Q1 2027
- Generated AFFO of $235 million and net cash flows from operating activities of $143 million
- Generated adjusted EBITDA of $322 million and a net loss of $131 million

"The completion of our PJM acquisition marks an extraordinary milestone for Capital Power as it underscores our ability to execute on our growth strategy and reaffirms our leadership in North American flexible generation. By expanding into North America's largest and most liquid power market, we have added approximately 2.2 GW of flexible generation capacity. The Hummel Station and Rolling Hills facilities are strategically positioned as young and highly efficient assets with significant commercial optimization potential that enjoy access to low-cost fuel" said Avik Dey, President and CEO of Capital Power. "This transaction enhances the positioning of our US generation fleet on these key metrics, supporting long-term shareholder value creation."

"This quarter reflects our continued success in delivering on our strategic priorities of growth, disciplined capital allocation, and diversification while maintaining a strong balance sheet. The recent acquisitions of Hummel Station and Rolling Hills significantly expand our U.S. footprint and are accretive to AFFO per share. Over the past year, we executed our largest acquisition, completed our most ambitious organic growth initiative—the Genesee repowering project, increased our dividend, and remain well within our financial guardrails that underpin our investment-grade credit rating. These milestones highlight our disciplined execution and reinforce our confidence in delivering long-term, sustainable value for shareholders." said Sandra Haskins, SVP Finance and CFO of Capital Power.

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1 Pennsylvania-New Jersey-Maryland Interconnection.

2 As previously announced, converted from US dollars to Canadian dollars using a 1.3684 exchange rate, as reported by the Bank of Canada on June 9, 2025.

3 Flexible generation is defined as natural gas generation assets and energy storage business.

4 Converted from US dollars to Canadian dollars using a 1.3933 exchange rate, as reported by the Bank of Canada on May 13, 2025.

Revised 2025 Annual Guidance

Priority	2025 target	Status at June 30, 2025
Execution of major turnarounds	Sustaining capital expenditures[3] • Revised guidance: **$215 million to $245 million** • 2025 original target**: $195 million to $225 million**	**$73 million[1,2]**
Generate financial stability and strength	AFFO[3,4] • Revised guidance: **$950 million to $1,100 million** • 2025 original target: **$850 million to $950 million**	**$453 million[1]**
	Adjusted EBITDA[3,4] • Updated guidance: **$1,500 million to $1,650 million** • 2025 original target: **$1,340 million to $1,440 million**	**$689 million[1]**

1 For the six months ended June 30, 2025.

2 Includes our share of equity-accounted investments sustaining capital expenditures of $32 million net of partner contributions of $6 million.

3 Based on the Company's year-to-date results, expectations for the remainder of the year and the expected results from the acquisition of Hummel Station, LLC and Rolling Hills, LLC for the periods subsequent to the close of the transaction on June 9, 2025, the Company provided updated guidance for 2025.

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

Operational and Financial Highlights[1]

($ millions, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Electricity generation (Gigawatt hours) [2]	9,022	8,603	18,578	17,412
Generation facility availability [3]	93%	91%	91%	92%
Revenues and other income	441	774	1,429	1,893
Adjusted EBITDA [4]	322	323	689	612
Net (loss) income	(131)	76	19	281
Net (loss) income attributable to shareholders of the Company	(132)	75	19	280
Basic (loss) earnings per share ($)	(0.92)	0.51	0.03	2.06
Diluted (loss) earnings per share ($) [5]	(0.92)	0.51	0.03	2.06
Net cash flows from operating activities	143	136	353	470
Adjusted funds from operations [4]	235	178	453	327
Adjusted funds from operations per share ($) [4]	1.55	1.37	3.12	2.58
Purchase of property, plant and equipment and other assets, net	141	226	429	444
Dividends per common share, declared ($)	0.6519	0.6150	1.3038	1.2300

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 six months ended June 30, 2025.

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

3 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.

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

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

Significant Events

Acquisition of Hummel Station and Rolling Hills

On June 9, 2025, Capital Power completed its previously announced acquisition of 100% of the equity interests in:

- Hummel Station, LLC, owner of the 1,124MW Hummel combined cycle natural gas facility in Shamokin Dam, Pennsylvania (the Hummel Acquisition); and
- Rolling Hills Generating, LLC, owner of the 1,023MW Rolling Hills Generation plant, a combustion turbine natural gas facility in Wilkesville, Ohio (the Rolling Hills Acquisition and together with Hummel Acquisition, the Acquisition).

The Acquisition expands the Company's operations into the PJM interconnection market and adds to its U.S. flexible generation fleet.

The total purchase price of the Acquisition was $3.0 billion (US$2.2 billion) in total cash consideration, including working capital and other closing adjustments.

Capital Power partially financed the acquisition with net proceeds from an offering of common shares and a private offering of senior notes, described in further detail below. The balance of the Acquisition was funded with additional cash on hand and a drawdown on the Company's existing revolving credit facilities.

$1.7 billion (US$1.2 billion) senior notes offering

On May 28, 2025, Capital Power closed a private placement offering of $966 million (US$700 million) aggregate principal amount of 5.257% senior notes due 2028 and $690 million (US$500 million) aggregate principal amount of 6.189% senior notes due 2035 issued by Capital Power (US Holdings) Inc., a U.S. wholly-owned subsidiary of the Company. The notes are guaranteed by the Company and the Company's subsidiaries that guarantee the Company's revolving credit facilities. The net proceeds of the offering were used to fund a portion of the Acquisition.

$667 million bought deal offering of common shares

On April 22, 2025, the Company completed its bought deal offering of 11,902,500 common shares of Capital Power, which included 1,552,500 common shares issued pursuant to the full exercise of the over-allotment option, at an offering price of $43.45 per common share (the Offering Price), for total gross proceeds of approximately $517 million (the Public Offering).

Concurrently, the Company issued 3,455,000 common shares at the Offering Price to Alberta Investment Management Corporation on a private placement basis for gross proceeds of approximately $150 million.

The net proceeds of the offerings were used to partially finance the Acquisition.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on July 30, 2025 at 9:00 am (MT) to discuss the second quarter financial results. The webcast can be accessed at: https://edge.media-server.com/mmc/p/ovx9eaxq. Conference call details will be sent directly to analysts.

An archive of the webcast will be available on the Company's website at www.capitalpower.com following the conclusion of the analyst conference call.

Non-GAAP Financial Measures and Ratios

Capital Power uses (i) earnings before, income tax expense, depreciation and amortization, net finance expense, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, other expenses from our joint venture interests, acquisition and integration costs, and other items that are not reflective of the Company's facility operating performance (adjusted EBITDA), and (ii) AFFO as specified financial measures. Adjusted EBITDA and AFFO are both non-GAAP financial measures.

Capital Power also uses AFFO per share as a specified performance measure. This measure is a non-GAAP ratio determined by applying AFFO to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of Capital Power, 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 our results of operations from management's perspective.

Adjusted EBITDA

During the second quarter of 2025, the Company amended the composition of adjusted EBITDA to exclude acquisition and integration costs, as these costs are not reflective of facility operating performance. The Company has applied this change to all historical amounts reported. 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 are excluded from the adjusted EBITDA measure such as impairments, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, acquisition and integration costs, and other items that are not reflective of the long-term performance of the Company's underlying operations.

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

($ millions)	Three months ended June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Revenues and other income	441	774	1,429	1,893
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(455)	(504)	(1,083)	(1,181)
Remove unrealized changes in fair value of commodity derivatives and emission credits	247	(8)	189	(208)
Remove other non-recurring items[1]	-	4	4	4
Adjusted EBITDA from joint ventures [2]	52	57	113	94
Remove acquisition and integration costs	37	-	37	10
Adjusted EBITDA	**322**	**323**	**689**	**612**
Depreciation and amortization	(138)	(120)	(264)	(242)
Unrealized changes in fair value of commodity derivatives and emission credits	(247)	8	(189)	208
Other non-recurring items	-	(4)	(4)	(4)
Acquisition and integration costs	(37)	-	(37)	(10)
Foreign exchange gains (losses)	21	(4)	23	(14)
Net finance expense	(64)	(53)	(125)	(95)
Losses on disposals and other transactions	(6)	(17)	(7)	(15)
Other items[2,3]	(36)	(34)	(73)	(59)
Income tax recovery (expense)	54	(23)	6	(100)
Net (loss) income	**(131)**	**76**	**19**	**281**
Net (loss) income attributable to:				
Non-controlling interests	1	1	-	1
Shareholders of the Company	(132)	75	19	280
Net (loss) income	**(131)**	**76**	**19**	**281**

1 For the six months ended June 30, 2025, and the three and six months ended June 30, 2024, other non-recurring items reflect costs related to the end-of-life of Genesee coal operations.

2 Total income from joint ventures as per our consolidated statements of income (loss).

3 Includes finance expense, depreciation expense and unrealized changes in fair value of derivative instruments from equity-accounted investments.

AFFO and AFFO per share

AFFO and AFFO per share are measures of our ability to generate cash from our operating activities to fund growth capital expenditures, repayment of debt, and payment of common share dividends. During the second quarter of 2025, the Company amended the composition of AFFO and AFFO per share to exclude acquisition and integration costs, as these costs are not reflective of cash generated from facility operations. The Company has applied this change to all historical amounts reported.

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 our share of AFFO of joint venture interests and exclude distributions received from our joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from off-coal compensation received annually through to 2030,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only Capital Power'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 our bank margin account held with a specific exchange counterparty,
- exclude acquisition and integration costs, and
- exclude other typically non-recurring items affecting cash flows from operating activities that are not reflective of the long-term performance of the Company's underlying business.

A reconciliation of net cash flows from operating activities to AFFO is as follows:

($ millions)	Three months ended June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**143**	**136**	**353**	**470**
Add (deduct):				
Interest paid	30	11	115	59
Change in fair value of derivatives reflected as cash settlement	18	(7)	7	(19)
Realized gain on settlement of interest rate derivatives	(17)	(14)	(17)	(14)
Distributions received from joint ventures	(33)	(3)	(38)	(11)
Miscellaneous financing charges paid [1]	(4)	-	(6)	(7)
Income taxes (recovered) paid	(1)	5	(3)	20
Change in non-cash operating working capital	79	92	54	(70)
	72	84	112	(42)
Net finance expense [2]	(58)	(45)	(111)	(80)
Current income tax recovery (expense) [3]	29	(6)	56	(22)
Sustaining capital expenditures [4]	(10)	(36)	(41)	(61)
Preferred share dividends paid	(6)	(9)	(13)	(18)
Cash received for off-coal compensation [5]	10	-	10	-
Remove tax equity interests' respective shares of AFFO	(2)	(2)	(3)	(3)
AFFO from joint ventures	26	38	63	59
Acquisition and integration costs [6]	38	-	38	7
Other non-recurring items [7]	(7)	18	(11)	17
AFFO	**235**	**178**	**453**	**327**
Weighted average number of common shares outstanding (millions)	151.2	129.5	145.2	126.6
AFFO per share ($)	**1.55**	**1.37**	**3.12**	**2.58**

[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] Excludes current income tax expense related to the partial divestiture of Quality Wind and Port Dover and Nanticoke Wind as the amount is classified as an investing activity.

[4] Includes sustaining capital expenditures net of partner contributions of $2 million and $6 million for the three and six months ended June 30, 2025, respectively, compared with $1 million and $6 million for the three and six months ended June 30, 2024, respectively.

[5] Reflects payment received from the Government of Alberta (GoA) during the three months ended June 30, 2025, for the settlement of previously disputed coal compensation payments as described in the Company's 2024 annual consolidated financial statements.

[6] For the three and six months ended June 30, 2025, net of current income tax expenses of $1 million, compared with $3 million for the six months ended June 30, 2024.

[7] For the three months ended June 30, 2025, other non-recurring items reflect current income tax expenses of $7 million related to other non-recurring items recognized in prior periods. For the six months ended June 30, 2025, other non-recurring items reflect costs related to the end-of-life of Genesee coal operations of $5 million, net of current income tax expenses of $16 million. For the three and six months ended June 30, 2024, other non-recurring items reflects costs related to the end-of-life of Genesee coal operations of $4 million and a provision of $18 million for the discontinuation of the Genesee CCS project related to the termination of sequestration hub evaluation work, net of current income tax expenses of $4 million and $5 million for the three and six months ended June 30, 2024, related to other non-recurring items recognized in the prior and current periods, respectively.

Forward-looking Information

Forward-looking information or statements included in this MD&A are provided to inform our 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 priorities and long-term strategies, including our corporate, and decarbonization strategies,
- our 2025 performance targets, including sustaining capital expenditures, adjusted funds from operations (AFFO) and adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA),
- future revenues, expenses, earnings, adjusted EBITDA and AFFO,
- the future pricing of electricity and market fundamentals in existing and target markets,
- our future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- our sources of funding, adequacy and availability of committed bank credit facilities and future borrowings,

  various aspects around existing, planned and potential development projects and acquisitions. This includes expectations around timing, transaction close timing and receipt of required regulatory approvals, and the satisfaction of other customary closing conditions, funding, project and acquisition costs, generation capacity, costs of technologies selected, environmental and sustainability benefits, and commercial and partnership arrangements,
- our 2025 estimated capital expenditures for previously announced growth projects,
- the performance of future projects and the performance of such projects in comparison to the market,
- plans and results related to the acquisition of Hummel Station, LLC (Hummel Station) and Rolling Hills Generating, L.L.C. (Rolling Hills),
- the return to operation of the downed unit at the Rolling Hills facility;
- anticipated pricing trends, growth opportunities, market conditions, and future power demand in the Pennsylvania-New Jersey-Maryland market,
- legislative developments regarding carbon pricing in Pennsylvania and Ohio,
- future growth and emerging opportunities in our target markets,
- market and regulation designs and regulatory and legislative proposals and changes, regulatory updates and the impact thereof on the Company's core markets and business, and
- the impact of climate change, including our assumptions relating to our identification of future risks and opportunities from climate change, our plans to mitigate transition and physical climate risks, and opportunities resulting from those risks.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes are appropriate including its review of purchased businesses and assets. The material factors and assumptions used to develop these forward-looking statements relate to:

- electricity and other energy and carbon prices,
- performance,
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- the status and impact of policy, legislation and regulations,
- effective tax rates,
- the development and performance of technology,
- the outcome of claims and disputes,
- foreign exchange rates, and
- other matters discussed under the Performance Outlook and Risks and Risk Management sections of this MD&A.

Whether actual results, performance or achievements will conform to our 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 our expectations. Such material risks and uncertainties are:

- changes in electricity, natural gas and carbon prices in markets in which we operate and the use of derivatives,
- regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation,
- disruptions, or price volatility within our supply chains,
- generation facility availability, wind capacity factor and performance including maintenance expenditures,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in the availability of fuel,
- ability to realize the anticipated benefits of acquisitions,
- limitations inherent in our review of acquired assets,
- changes in general economic and competitive conditions, including inflation and recession,
- 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 of this MD&A.

See Risks and Risk Management in our 2024 Integrated Annual Report, 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. Capital Power 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 our expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

Territorial Acknowledgement

In the spirit of reconciliation, Capital Power respectfully acknowledges that we operate within the ancestral homelands, traditional and treaty territories of the Indigenous Peoples of Turtle Island, or North America. Capital Power's head office is located within the traditional and contemporary home of many Indigenous Peoples of the Treaty 6 region and Métis Nation of Alberta Region 4. We acknowledge the diverse Indigenous communities that are located in these areas and whose presence continues to enrich the community.

About Capital Power

Capital Power is a growth-oriented power producer with approximately 12 GW of power generation at 32 facilities across North America. We prioritize safely delivering reliable and affordable power communities can depend on, building lower-carbon power systems, and creating balanced solutions for our energy future. We are Powering Change by Changing Power™.

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CAPITAL POWER CORPORATION

Management’s Discussion and Analysis

This Management’s Discussion and Analysis (MD&A), prepared as of July 29, 2025, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the six months ended June 30, 2025, the audited consolidated financial statements and the 2025 Performance Targets, Powering the Energy Expansion and Business Report sections of the Integrated Annual Report of Capital Power Corporation for the year ended December 31, 2024 (the 2024 Integrated Annual Report), the Annual Information Form of Capital Power Corporation dated February 25, 2025, and the cautionary statements regarding Forward-Looking Information which begin on page 9.

Effective January 1, 2025, the Company reassessed its reportable segments due to changes in internal reporting for performance results provided to the Company's Chief Operating Decision Maker (CODM). These operating segments are now grouped by both business activity and geographical areas into flexible generation and renewables and Canada and U.S. Prior to 2025, these segments were based on geographical areas. Comparative segment information has been restated to conform to the current period’s presentation. References to flexible generation are defined as natural gas generation assets and energy storage.

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 six months ended June 30, 2025 and June 30, 2024 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board 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 July 29, 2025.

FORWARD-LOOKING INFORMATION

Forward-looking information or statements included in this MD&A are provided to inform our 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 priorities and long-term strategies, including our corporate, and decarbonization strategies,
- our 2025 performance targets, including sustaining capital expenditures, adjusted funds from operations (AFFO) and adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA),
- future revenues, expenses, earnings, adjusted EBITDA and AFFO,
- the future pricing of electricity and market fundamentals in existing and target markets,
- our future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- our sources of funding, adequacy and availability of committed bank credit facilities and future borrowings,
  various aspects around existing, planned and potential development projects and acquisitions. This includes expectations around timing, transaction close timing and receipt of required regulatory approvals, and the satisfaction of other customary closing conditions, funding, project and acquisition costs, generation capacity, costs of technologies selected, environmental and sustainability benefits, and commercial and partnership arrangements,
- our 2025 estimated capital expenditures for previously announced growth projects,
- the performance of future projects and the performance of such projects in comparison to the market,
- plans and results related to the acquisition of Hummel Station, LLC (Hummel Station) and Rolling Hills Generating, L.L.C. (Rolling Hills),
- the return to operation of the downed unit at the Rolling Hills facility,
- anticipated pricing trends, growth opportunities, market conditions, and future power demand in the Pennsylvania-New Jersey-Maryland (PJM) market,
- legislative developments regarding carbon pricing in Pennsylvania and Ohio,
- future growth and emerging opportunities in our target markets,
- market and regulation designs and regulatory and legislative proposals and changes, regulatory updates and the impact thereof on the Company's core markets and business, and
- the impact of climate change, including our assumptions relating to our identification of future risks and opportunities from climate change, our plans to mitigate transition and physical climate risks, and opportunities resulting from those risks.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes are appropriate including its review of purchased businesses and assets. The material factors and assumptions used to develop these forward-looking statements relate to:

- electricity and other energy and carbon prices,
- performance,
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- the status and impact of policy, legislation and regulations,
- effective tax rates,
- the development and performance of technology,
- the outcome of claims and disputes,
- foreign exchange rates, and
- other matters discussed under the Performance Outlook and Risks and Risk Management sections of this MD&A.

Whether actual results, performance or achievements will conform to our 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 our expectations. Such material risks and uncertainties are:

- changes in electricity, natural gas and carbon prices in markets in which we operate and the use of derivatives,
- regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation,
- disruptions, or price volatility within our supply chains,
- generation facility availability, wind capacity factor and performance including maintenance expenditures,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in the availability of fuel,
- ability to realize the anticipated benefits of acquisitions,
- limitations inherent in our review of acquired assets,
- changes in general economic and competitive conditions, including inflation and recession,
- 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 of this MD&A.

See Risks and Risk Management in our 2024 Integrated Annual Report, 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. Capital Power 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 our 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 power producer with approximately 12 GW of owned power generation at 32 facilities across North America. We prioritize safely *delivering* reliable and affordable power communities can depend on, *building* lower-carbon power systems, and *creating* balanced solutions for our energy future. We are Powering Change by Changing Power™.

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.

PERFORMANCE 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.

We measure our operational and financial performance in relation to our corporate strategy through financial and non-financial targets that are approved by the Board of Directors. The measurement categories include corporate measures and measures specific to certain groups within Capital Power. The corporate measures are company-wide and include adjusted EBITDA, AFFO and safety. The group-specific measures include facility operating margin and other operations measures, committed capital, construction and sustaining capital expenditures on budget and on schedule, and facility site safety.

The updated 2025 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts, and the performance of the Hummel Station and Rolling Hills facilities. They do not include the effects of asset sell-downs, potential future acquisitions or development activities, or potential market and operational impacts relating to significant unplanned facility outages including outages at facilities of other market participants, and the related impacts on market power prices.

Operational priorities and performance targets for Capital Power in 2025 include a balanced approach to the energy transition:

Priority	2025 target	Status at June 30, 2025
Deliver		
Execution of major turnarounds	Sustaining capital expenditures[3] • Revised guidance: **$215 million to $245 million** • 2025 original target: **$195 million to $225 million**	**$73 million[1,2]**
Generate financial stability and strength	AFFO[3,4] • Revised guidance: **$950 million to $1,100 million** • 2025 original target: **$850 million to $950 million**	**$453 million[1]**
	Adjusted EBITDA[3,4] • Updated guidance: **$1,500 million to $1,650 million** • 2025 original target: **$1,340 million to $1,440 million**	**$689 million[1]**
Portfolio optimization and integration	Re-contract/contract flexible generation Maximize facility asset life and value	Discussions with counterparties are in progress to re-contract flexible generation.
Build		
Expand flexible generation portfolio	Continue construction on Ontario growth and commercial initiative projects Continue to explore opportunities to build or acquire flexible generation facilities	Construction is underway and the projects remain on track to meet their targeted completion dates (see Capital Expenditures and Investments). Reached commercial operation of the 40MW uprate project at Goreway. The Ontario BESS projects are substantially complete and commissioning is currently underway. East Windsor environmental permits have been received and all major equipment is on site. Site civil work and foundations are advanced. On June 9, 2025, the Company completed the acquisition of two U.S. flexible generation assets in the PJM market, Hummel Station and Rolling Hills (see Significant Events).
Grow renewables portfolio	Continue construction on Alberta and North Carolina growth and commercial initiative projects Continue to explore opportunities to build or acquire renewables facilities	Construction for Hornet Solar commenced during the first quarter of 2025. Bear Branch Solar and Maple Leaf Solar commenced construction in the second quarter of 2025. These projects remain on schedule for targeted completion (see Capital Expenditures and Investments).
Create		
Balanced energy solutions	Evaluate Small Modular Reactors (SMRs) in Alberta	Pre-feasibility study work for the Alberta SMR project with Ontario Power Generation remains on track. The first funded phase of the project is completed.
	Provide integrated energy solutions to commercial and industrial customers	Discussions with counterparties are in progress to provide integrated energy solutions.

1 For the six months ended June 30, 2025.

2 Includes our share of equity-accounted investments sustaining capital expenditures of $32 million net of partner contributions of $6 million.

3 Based on the Company's year-to-date results, expectations for the remainder of the year and the expected results from the acquisition of Hummel Station, LLC and Rolling Hills, LLC for the periods subsequent to the close of the transaction on June 9, 2025, the Company provided updated guidance for 2025.

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

On July 30, 2025, the Company provided updated guidance for its 2025 AFFO, adjusted EBITDA and sustaining capital expenditures based on the actual year-to-date results for 2025, the Company's forecast for the remainder of the year, and the significant events that occurred during the quarter including: the acquisition of the Hummel Station and Rolling Hills facilities in PJM and the issuance of senior notes (see Significant Events). The Company expects 2025 full year results to be within the revised guidance ranges. Integrating the Hummel Station and Rolling Hills facilities is a priority for the remainder of 2025.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2026, 2027 and 2028 (all at June 30, 2025) were:

Alberta portfolio	2026	2027	2028
Power			
Hedged volume (GWh)	12,000	6,000	3,000
Weighted average hedged prices [1] ($/MWh)	Low-$70s	High-$70s	High-$70s
Forward Alberta pool prices ($/MWh)	$54	$61	$75
Natural gas			
Hedged volume (TJ)	70,000	50,000	25,000
Weighted average hedged prices [1,2] ($/GJ)	< $4.00	< $4.00	< $4.00
Forward Alberta natural gas prices ($/GJ)	$3.20	$3.20	$3.20

1 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. When long-term forward portfolio optimization hedges are transacted, they reflect the market's expectations for future period pricing.

2 Net of gains as part of the Company's natural gas portfolio optimization activities, including sales of previously purchased length.

The power hedged volumes and weighted average hedged prices include origination contracts with contract terms greater than 12 months. The weighted average hedged price of these longer-term duration contracts is in the high-$70s per megawatt hour range. In addition to the remaining open baseload position, Alberta natural gas peaking assets in the Company's Canada flexible generation portfolio are available to capture upside from higher Alberta power prices.

Our board has approved a 6% increase in the common share dividend for 2025 and we continue to anticipate a long-term targeted dividend growth of 2% – 4% after 2025, as previously announced at our Investor Day Presentation in May 2024. The reduction of our targeted dividend growth after 2025 aligns with our strategy to reinvest cash flows and to fund future growth opportunities. Each annual increase is premised on the assumptions listed under Forward-Looking Information and subject to approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of expected sources of funding.

NON-GAAP FINANCIAL MEASURES AND RATIOS

Capital Power uses (i) earnings before, income tax expense, depreciation and amortization, net finance expense, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, other expenses from our joint venture interests, acquisition and integration costs, and other items that are not reflective of the Company's facility operating performance (adjusted EBITDA), and (ii) AFFO as specified financial measures. Adjusted EBITDA and AFFO are both non-GAAP financial measures.

Capital Power also uses AFFO per share as a specified performance measure. This measure is a non-GAAP ratio determined by applying AFFO to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of Capital Power, 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 our results of operations from management's perspective.

Adjusted EBITDA

During the second quarter of 2025, the Company amended the composition of adjusted EBITDA to exclude acquisition and integration costs, as these costs are not reflective of facility operating performance. The Company has applied this change to all historical amounts reported. 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 are excluded from the adjusted EBITDA measure such as impairments, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, acquisition and integration costs, and other items that are not reflective of the long-term performance of the Company's underlying operations.

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

($ millions)	Three months ended June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Revenues and other income	441	774	1,429	1,893
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(455)	(504)	(1,083)	(1,181)
Remove unrealized changes in fair value of commodity derivatives and emission credits	247	(8)	189	(208)
Remove other non-recurring items[1]	-	4	4	4
Adjusted EBITDA from joint ventures [2]	52	57	113	94
Remove acquisition and integration costs	37	-	37	10
Adjusted EBITDA	**322**	**323**	**689**	**612**
Depreciation and amortization	(138)	(120)	(264)	(242)
Unrealized changes in fair value of commodity derivatives and emission credits	(247)	8	(189)	208
Other non-recurring items	-	(4)	(4)	(4)
Acquisition and integration costs	(37)	-	(37)	(10)
Foreign exchange gains (losses)	21	(4)	23	(14)
Net finance expense	(64)	(53)	(125)	(95)
Losses on disposals and other transactions	(6)	(17)	(7)	(15)
Other items[2,3]	(36)	(34)	(73)	(59)
Income tax recovery (expense)	54	(23)	6	(100)
Net (loss) income	**(131)**	**76**	**19**	**281**
Net (loss) income attributable to:				
Non-controlling interests	1	1	-	1
Shareholders of the Company	(132)	75	19	280
Net (loss) income	**(131)**	**76**	**19**	**281**

[1] For the six months ended June 30, 2025, and the three and six months ended June 30, 2024, other non-recurring items reflect costs related to the end-of-life of Genesee coal operations.

[2] Total income from joint ventures as per our consolidated statements of income (loss).

[3] Includes finance expense, depreciation expense and unrealized changes in fair value of derivative instruments from equity-accounted investments.

AFFO and AFFO per share

AFFO and AFFO per share are measures of our ability to generate cash from our operating activities to fund growth capital expenditures, repayment of debt, and payment of common share dividends. During the second quarter of 2025, the Company amended the composition of AFFO and AFFO per share to exclude acquisition and integration costs, as these costs are not reflective of cash generated from facility operations. The Company has applied this change to all historical amounts reported.

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 our share of AFFO of joint venture interests and exclude distributions received from our joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from off-coal compensation received annually through to 2030,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only Capital Power'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 our bank margin account held with a specific exchange counterparty,
- exclude acquisition and integration costs, and
- exclude other typically non-recurring items affecting cash flows from operating activities that are not reflective of the long-term performance of the Company's underlying business.

A reconciliation of net cash flows from operating activities to AFFO is as follows:

($ millions)	Three months ended June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**143**	**136**	**353**	**470**
Add (deduct):				
Interest paid	30	11	115	59
Change in fair value of derivatives reflected as cash settlement	18	(7)	7	(19)
Realized gain on settlement of interest rate derivatives	(17)	(14)	(17)	(14)
Distributions received from joint ventures	(33)	(3)	(38)	(11)
Miscellaneous financing charges paid [1]	(4)	-	(6)	(7)
Income taxes (recovered) paid	(1)	5	(3)	20
Change in non-cash operating working capital	79	92	54	(70)
	72	84	112	(42)
Net finance expense [2]	(58)	(45)	(111)	(80)
Current income tax recovery (expense) [3]	29	(6)	56	(22)
Sustaining capital expenditures [4]	(10)	(36)	(41)	(61)
Preferred share dividends paid	(6)	(9)	(13)	(18)
Cash received for off-coal compensation [5]	10	-	10	-
Remove tax equity interests' respective shares of AFFO	(2)	(2)	(3)	(3)
AFFO from joint ventures	26	38	63	59
Acquisition and integration costs [6]	38	-	38	7
Other non-recurring items [7]	(7)	18	(11)	17
AFFO	**235**	**178**	**453**	**327**
Weighted average number of common shares outstanding (millions)	151.2	129.5	145.2	126.6
AFFO per share ($)	**1.55**	**1.37**	**3.12**	**2.58**

[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] Excludes current income tax expense related to the partial divestiture of Quality Wind and Port Dover and Nanticoke Wind as the amount is classified as an investing activity.

[4] Includes sustaining capital expenditures net of partner contributions of $2 million and $6 million for the three and six months ended June 30, 2025, respectively, compared with $1 million and $6 million for the three and six months ended June 30, 2024, respectively.

[5] Reflects payment received from the Government of Alberta (GoA) during the three months ended June 30, 2025, for the settlement of previously disputed off-coal compensation payments as described in the Company's 2024 annual consolidated financial statements.

[6] For the three and six months ended June 30, 2025, net of current income tax recoveries of $1 million, compared with $3 million for the six months ended June 30, 2024.

[7] For the three months ended June 30, 2025, other non-recurring items reflect current income tax recoveries of $7 million related to other non-recurring items recognized in prior periods. For the six months ended June 30, 2025, other non-recurring items reflect costs related to the end-of-life of Genesee coal operations of $5 million, net of current income tax recoveries of $16 million. For the three and six months ended June 30, 2024, other non-recurring items reflects costs related to the end-of-life of Genesee coal operations of $4 million and a provision of $18 million for the discontinuation of the Genesee CCS project related to the termination of sequestration hub evaluation work, net of current income tax recoveries of $4 million and $5 million for the three and six months ended June 30, 2024, related to other non-recurring items recognized in the prior and current periods, respectively.

FINANCIAL HIGHLIGHTS

($ millions, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Revenues and other income	441	774	1,429	1,893
Adjusted EBITDA [1]	322	323	689	612
Net (loss) income	(131)	76	19	281
Net (loss) income attributable to shareholders of the Company	(132)	75	19	280
Basic (loss) earnings per share ($)	(0.92)	0.51	0.03	2.06
Diluted (loss) earnings per share ($) [2]	(0.92)	0.51	0.03	2.06
Net cash flows from operating activities	143	136	353	470
AFFO [1]	235	178	453	327
AFFO per share ($) [1]	1.55	1.37	3.12	2.58
Purchase of property, plant and equipment and other assets, net	141	226	429	444
Dividends per common share, declared ($)	0.6519	0.6150	1.3038	1.2300
Dividends per Series 1 preferred share, declared ($)	0.1638	0.1638	0.3276	0.3276
Dividends per Series 3 preferred share, declared ($)	0.4288	0.4288	0.8576	0.8576
Dividends per Series 5 preferred share, declared ($)	0.4144	0.4144	0.8288	0.8288
Dividends per Series 11 preferred share, declared ($) [3]	N/A	0.3594	N/A	0.7188

	As at	
	June 30, 2025	**December 31, 2024**
Loans and borrowings including current portion	6,941	4,976
Total assets	15,171	12,930

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

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

[3] On June 30, 2024, Capital Power redeemed all of its 6 million issued and outstanding 5.75% cumulative minimum rate reset preference shares, Series 11.

Adjusted EBITDA for the three months ended June 30, 2025 was consistent with the comparative period. For the six months ended June 30, 2025, adjusted EBITDA was higher than the corresponding period in 2024 largely due to the net impact of:

- higher contributions for the U.S. flexible generation segment due to full year results from La Paloma and Harquahala which were acquired in February 2024 and the Hummel Station and Rolling Hills facilities which were acquired in June, 2025 (see Significant Events),
- lower emissions costs in the Canada flexible generation segment given by the repowering of Genesse Generating Station to be off coal, offset by higher overall fuel costs, and
- lower corporate expenses driven by lower salary costs.

AFFO for the three months ended June 30, 2025, was higher than the corresponding period in 2024 primarily due to:

- current income tax recovery due to lower overall consolidated net income before tax,
- lower sustaining capital expenditures due mainly to a credit received for parts at La Paloma,
- settlement received for disputed coal compensation payments in the second quarter of 2025, and
- partly offset by higher finance expense from increased loans and borrowings due to issuances during the second quarter of 2025 and second half of 2024 and lower contributions from joint ventures.

AFFO for the six months ended June 30, 2025, was higher than the corresponding period in 2024 primarily due to:

- higher adjusted EBITDA, current income tax recovery, and lower sustaining capital expenditures described above,
- partly offset by higher finance expense described above.

Revenues and other income for the three and six months ended June 30, 2025, were lower than the corresponding periods in 2024 primarily due to losses on unrealized changes in fair value of commodity derivatives and emission credits as described in Consolidated Net Income and Results of Operations, and reduced power prices realized in the Canada flexible generation segment. Partly offsetting these decreases were increased revenues from U.S. flexible generation from La Paloma which was acquired in February 2024 and the Hummel Station and Rolling Hills facilities which were acquired in June 2025 (see Significant Events).

See Consolidated Net Income and Results of Operations for further 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.

Basic and diluted earnings per share changes 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.

See Liquidity and Capital Resources for discussion of key drivers of changes in net cash flows from operating activities.

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

SIGNIFICANT EVENTS

Acquisition of Hummel Station and Rolling Hills

On June 9, 2025, Capital Power completed its previously announced acquisition of 100% of the equity interests in:

- Hummel Station, LLC, owner of the 1,124MW Hummel combined cycle natural gas facility in Shamokin Dam, Pennsylvania (the Hummel Acquisition); and
- Rolling Hills Generating, LLC, owner of the 1,023MW Rolling Hills Generation plant, a combustion turbine natural gas facility in Wilkesville, Ohio (the Rolling Hills Acquisition and together with Hummel Acquisition, the Acquisition).

The Acquisition expands the Company's operations into the PJM interconnection market and adds to its U.S. flexible generation fleet.

Both the Hummel Station and Rolling Hills facilities sell their energy, ancillary services and capacity into the PJM market on a merchant basis. Energy margins are earned through a combination of day-ahead and real-time sale while capacity will be sold through the annual auction and potential interim balancing auctions as required.

The Hummel Station facility benefits from a strategically advantageous location with respect to gas supply. It is connected to the UGI Sunbury pipeline (Sunbury), which links to the Transco interstate pipeline in central Pennsylvania. The Hummel facility holds firm gas transport capacity on Sunbury, providing access to competitively priced Marcellus shale gas. The Hummel facility sources gas at the Leidy gas point which trades in the spot market at a discount to most other regional gas hubs.

Similar to the Hummel Station facility, the Rolling Hills facility is well positioned with respect to its gas supply as it has access to low-cost Marcellus Basin gas. It is connected to the Texas Eastern Transmission Corporation (TETCO) interstate pipeline and procurement occurs in the spot market. The facility sources its gas from the TETCO East Louisiana hub, which typically trades in the spot market at a discount compared to other regional gas hubs.

Currently, one unit at the Rolling Hills facility is out of service as a result of a Generator Step Up (GSU) transformer fire on or about September 12, 2024. The unit has been down while awaiting procurement of a replacement GSU, with a full unit restoration target date of December 2025. Lost revenues associated with the unit were negotiated as part of the purchase price, and the Company has insurance coverage for the cost of the replacement GSU.

The total purchase price of the Acquisition was $3.0 billion (US$2.2 billion) in total cash consideration, including working capital and other closing adjustments.

Capital Power partially financed the acquisition with net proceeds from an offering of common shares and a private offering of senior notes, described in further detail below. The balance of the Acquisition was funded with additional cash on hand and a drawdown on the Company's existing revolving credit facilities.

On July 22, 2025, PJM posted their Base Residual Auction (BRA) results for the 2026/2027 delivery year. The auction secured commitments for 134,311 MW of unforced capacity in the Regional Transmission Organization from annual, summer-period and winter-period matched resources and price-responsive demand. Prices for all locational deliverability areas (LDAs), including the LDAs where the Rolling Hills and Hummel facilities are located, cleared at the cap of US$329/MW-day, further supporting the economics of the Acquisition.

$1.7 billion (US$1.2 billion) senior notes offering

On May 28, 2025, Capital Power closed a private placement offering of $966 million (US$700 million) aggregate principal amount of 5.257% senior notes due 2028 and $690 million (US$500 million) aggregate principal amount of 6.189% senior notes due 2035 issued by Capital Power (US Holdings) Inc., a U.S. wholly-owned subsidiary of the Company. The notes are guaranteed by the Company and the Company's subsidiaries that guarantee the Company's revolving credit facilities. The net proceeds of the offering were used to fund a portion of the Acquisition.

$667 million bought deal offering of common shares

On April 22, 2025, the Company completed its bought deal offering of 11,902,500 common shares of Capital Power, which included 1,552,500 common shares issued pursuant to the full exercise of the over-allotment option, at an offering price of $43.45 per common share (the Offering Price), for total gross proceeds of approximately $517 million (the Public Offering).

Concurrently, the Company issued 3,455,000 common shares at the Offering Price to Alberta Investment Management Corporation on a private placement basis for gross proceeds of approximately $150 million.

The net proceeds of the offerings were used to partially finance the Acquisition.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net (loss) income for the three and six months ended June 30, 2025 compared with 2024 are presented below followed by further discussion of these items.

($ millions)	Three months		Six months	
Consolidated net income for the periods ended June 30, 2024		**76**		**281**
Increase (decrease) in adjusted EBITDA [1]:				
Canada flexible generation	3		31	
Canada renewables	(14)		(25)	
U.S. flexible generation	13		48	
U.S. renewables	(2)		1	
Corporate	(1)	(1)	22	77
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(255)		(397)
Decrease in loss on disposals and other transactions		11		8
Increase in depreciation and amortization expense		(18)		(22)
Increase in foreign exchange gain		25		37
Increase in finance expense and depreciation from equity-accounted investments		(2)		(14)
Increase in net finance expense		(11)		(30)
Acquisition and integration costs		(37)		(27)
Non-recurring items		4		-
Decrease in income before tax		(284)		(368)
Decrease in income tax expense		77		106
Decrease in net income		**(207)**		**(262)**
Consolidated net (loss) income for the periods ended June 30, 2025		**(131)**		**19**

[1] Adjusted EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures and Ratios

Results by facility category and other

	Three months ended June 30							
	2025	2024	2025	2024	2025	2024	2025	2024
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** ($ millions) [3]		**Adjusted EBITDA** ($ millions) [3]	
Total electricity generation, average facility availability and facility revenues	9,022	8,603	93	91	515	439		
Canada flexible generation								
Genesee Generating Station, Alberta [4]	2,457	2,028	91	96	102	100		
Clover Bar Energy Centre, Alberta	102	129	80	58	8	9		
Joffre, Alberta	167	139	100	80	14	13		
Shepard, Alberta	645	552	98	74	31	26		
Island Generation, British Columbia	-	-	100	100	2	3		
York Energy, Ontario [5]	20	12	67	100	N/A	N/A		
East Windsor, Ontario	4	2	99	99	10	8		
Goreway, Ontario	533	552	98	85	76	63		
EnPower, British Columbia	5	3	100	100	-	-		
Alberta portfolio optimization	N/A	N/A	N/A	N/A	229	251		
	3,933	3,417	91	88	472	473	166	163
Canada renewables								
Quality Wind, British Columbia [5]	51	93	98	98	N/A	10		
Halkirk 1 Wind, Alberta	100	106	95	95	7	9		
Halkirk 2 Wind, Alberta [6]	-	N/A	-	N/A	-	N/A		
Whitla Wind, Alberta	258	338	97	98	13	18		
Strathmore Solar, Alberta	31	25	97	97	1	1		
Clydesdale Solar, Alberta	58	52	97	97	5	5		
Kingsbridge 1, Ontario	20	19	93	94	2	2		
Port Dover and Nanticoke Wind, Ontario [5]	39	63	98	98	N/A	9		
	557	696	97	97	28	54	27	41
Total Canada	**4,490**	**4,113**	**92**	**92**	**500**	**527**	**193**	**204**
U.S. flexible generation								
Decatur Energy, Alabama	871	883	99	98	22	22		
Arlington Valley, Arizona	757	795	94	99	42	32		
Midland Cogen, Michigan [5]	1,172	1,444	95	95	N/A	N/A		
Frederickson 1, Washington	73	137	85	50	6	6		
Harquahala, Arizona [5,7]	233	333	89	80	N/A	N/A		
La Paloma, California [7]	245	317	97	94	82	65		
Hummel Station, Pennsylvania [8]	515	N/A	100	N/A	34	N/A		
Rolling Hills, Ohio [8]	160	N/A	100	N/A	21	N/A		
U.S. Trading	N/A	N/A	N/A	N/A	6	13		
	4,026	3,909	96	86	213	138	141	128
U.S. renewables								
Beaufort Solar, North Carolina	7	7	99	99	-	-		
Bloom Wind, Kansas	159	184	90	94	12	12		
Macho Springs Wind, New Mexico	39	41	95	96	5	5		
New Frontier Wind, North Dakota	89	107	91	95	5	7		
Cardinal Point Wind, Illinois	122	143	83	84	9	10		
Buckthorn Wind, Texas	90	99	92	96	8	6		
	506	581	89	94	39	40	27	29
Total U.S.	**4,532**	**4,490**	**95**	**90**	**252**	**178**	**168**	**157**
Corporate [9]					17	-	(39)	(38)
Unrealized changes in fair value of commodity derivatives and emission credits					(328)	69		
Consolidated revenues and other income and adjusted EBITDA					**441**	**774**	**322**	**323**

	Six months ended June 30							
	2025	2024	2025	2024	2025	2024	2025	2024
	Electricity generation (GWh) [1]		Facility availability (%) [2]		Revenues and other income ($ millions) [3]		Adjusted EBITDA ($ millions) [3]	
Total electricity generation, average facility availability and facility revenues	18,578	17,412	91	92	1,121	1,118		
Canada flexible generation								
Genesee Generating Station, Alberta [4]	5,212	4,416	91	94	218	343		
Clover Bar Energy Centre, Alberta	216	294	78	57	16	31		
Joffre, Alberta	331	354	99	90	29	41		
Shepard, Alberta	1,357	1,372	99	86	62	86		
Island Generation, British Columbia	74	34	100	100	4	6		
York Energy, Ontario [5]	31	18	79	100	N/A	N/A		
East Windsor, Ontario	10	14	99	99	18	16		
Goreway, Ontario	1,487	1,351	94	92	191	148		
EnPower, British Columbia	14	9	100	93	1	1		
Alberta portfolio optimization	N/A	N/A	N/A	N/A	513	478		
	8,732	7,862	92	91	1,052	1,150	373	342
Canada renewables								
Quality Wind, British Columbia [5]	102	180	98	97	N/A	25		
Halkirk 1 Wind, Alberta	221	215	96	94	17	22		
Halkirk 2 Wind, Alberta [6]	-	N/A	-	N/A	-	N/A		
Whitla Wind, Alberta	566	663	97	96	28	33		
Strathmore Solar, Alberta	43	38	96	97	2	2		
Clydesdale Solar, Alberta	81	84	97	97	6	7		
Kingsbridge 1, Ontario	60	47	95	92	5	4		
Port Dover and Nanticoke Wind, Ontario [5]	81	145	89	98	N/A	22		
	1,154	1,372	97	97	58	115	60	85
Total Canada	**9,886**	**9,234**	**93**	**93**	**1,110**	**1,265**	**433**	**427**
U.S. flexible generation								
Decatur Energy, Alabama	1,941	1,338	199	99	57	48		
Arlington Valley, Arizona	1,409	1,635	84	90	112	85		
Midland Cogen, Michigan [5]	2,272	2,742	94	94	N/A	N/A		
Frederickson 1, Washington	265	383	91	69	12	12		
Harquahala, Arizona [5,7]	371	333	84	87	N/A	N/A		
La Paloma, California [7]	668	594	86	95	210	108		
Hummel Station, Pennsylvania [8]	516	N/A	100	N/A	34	N/A		
Rolling Hills, Ohio [8]	160	N/A	100	N/A	21	N/A		
U.S. Trading	N/A	N/A	N/A	N/A	17	20		
	7,602	7,025	91	89	463	273	260	212
U.S. renewables								
Beaufort Solar, North Carolina	13	14	99	99	1	1		
Bloom Wind, Kansas	315	358	90	96	20	22		
Macho Springs Wind, New Mexico	79	82	96	96	10	10		
New Frontier Wind, North Dakota	206	196	93	89	12	12		
Cardinal Point Wind, Illinois	291	308	82	85	22	22		
Buckthorn Wind, Texas	186	195	94	96	15	13		
	1,090	1,153	90	93	80	80	58	57
Total U.S.	**8,692**	**8,178**	**91**	**91**	**543**	**353**	**318**	**269**
Corporate [9]					31	3	(62)	(84)
Unrealized changes in fair value of commodity derivatives and emission credits					(255)	272		
Consolidated revenues and other income and adjusted EBITDA					**1,429**	**1,893**	**689**	**612**

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

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

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

[4] Genesee repowered units 1 and 2 simple cycle commissioned May 3, 2024 and June 28, 2024, respectively and dual cycle commissioned November 18, 2024 and December 13, 2024, respectively. Genesee Units 1, 2 and 3 are now presented together as the Genesee Generating Station.

[5] Quality Wind, York Energy, Port Dover and Nanticoke Wind, Midland Cogeneration and Harquahala are accounted for under the equity method. Capital Power's share of each facility's net income is included in income from equity-accounted investments on our consolidated statements of income. Capital Power's share of each facility's adjusted EBITDA is included in adjusted EBITDA above.

Quality Wind and Port Dover and Nanticoke Wind were partially divested on December 20, 2024. Revenues and other income and adjusted EBITDA are included up until December 20, 2024, for Capital Power's full ownership.

The equivalent of Capital Power's share of the facilities revenue was $121 million and $270 million for the three and six months ended June 30, 2025 respectively, compared with $110 million and $209 million for three and six months ended June 30, 2024, respectively. The facilities revenues are not included in the above results.

[6] Halkirk 2 Wind commenced partial operations in the fourth quarter of 2024 with commercial operations expected in the fourth quarter of 2025 (see Capital Expenditures and Investments).

[7] Harquahala and La Paloma were acquired February 16, 2024 and February 9, 2024, respectively.

[8] Hummel Station and Rolling Hills facilities were acquired June 9, 2025.

[9] Corporate revenues are partly offset by interplant category eliminations.

Canada flexible generation energy prices and hedged positions

	Three months ended June 30		Six months ended June 30	
Alberta commercial portfolio	**2025**	**2024**	**2025**	**2024**
Power				
Hedged volume at beginning of period (GWh)	3,000	2,500	6,000	5,500
Spot power price average ($/MWh)	40	45	40	72
Realized power price average [1] ($/MWh)	73	78	74	80
Natural gas				
Hedged volume at beginning of period (TJ)	15,000	18,000	37,500	34,500
Spot natural gas price average (AECO) [2] ($/GJ)	1.64	1.14	1.83	1.54

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

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

Canada flexible generation

Alberta spot price averaged $40 per MWh for the second quarter and first half of 2025, compared to $45 per MWh and $72 per MWh in the same periods last year. Mild temperatures across the province throughout the majority of the period and improved thermal supply resulted in lower Alberta settled and captured pricing by our Alberta portfolio year-over-year.

Generation and availability for the three and six months ended June 30, 2025 increased compared to the same periods in the previous year due to the following net effect:

- increased generation at Genesee Generation Station due to incremental capacity gained from the repowering of units 1 & 2 which achieved commercial operations in the fourth quarter of 2024. Availability decreased in 2025 due to planned outages that occurred during the second quarter,
- lower dispatch and generation at Clover Bar Energy Center, Joffre and Shepard due to lower year-over-year power pricing, and
- increased availability and generation year-over-year at Goreway due to tighter market conditions with increased load demand, increased exports and colder weather early in 2025 compared to 2024.

Lower revenues and other income for the three and six months ended June 30, 2025, compared to the same periods in 2024 were primarily due to reduced power pricing realized by the Alberta portfolio slightly offset by higher generation as listed above.

Adjusted EBITDA was favorable year-over-year due to lower emissions costs from reduced intensity driven by a shift to natural gas versus coal consumption at the Genesee Generating Station, which more than offset the lower power prices and higher gas prices realized in the Alberta portfolio in 2025 compared to 2024.

Canada renewables

While availability was consistent year-over-year, generation and revenues and other income and adjusted EBITDA were lower in 2025 primarily due to the renewable asset sell-down of the Quality Wind and Port Dover and Nanticoke facilities in the fourth quarter of 2024. Lower Alberta power prices further reduced revenues and other income and adjusted EBITDA at Halkirk and lower generation from lower wind resource at Whitla.

U.S. flexible generation

Generation and availability for the three and six months ended June 30, 2025, increased compared to the same periods in 2024 due to the following net effect:

- acquisition of the Hummel Station and Rolling Hills facilities in June 2025 (see Significant Event),
- full year of generation at the Harquahala and La Paloma facilities in 2025 that were acquired in February 2024, slightly offset by a planned outage at La Paloma in 2025,
- lower generation at MCV due to higher fuel costs.

Revenues and other income and adjusted EBITDA for the six months ended June 30, 2025 was higher than prior year due to higher captured prices at La Paloma and Arlington as a result of various outages in the area, acquisitions of the Hummel Station and Rolling Hills facilities (see Significant Events) and favorable foreign exchange with a stronger U.S. currency.

U.S. renewables

The results of U.S. renewables remained consistent year-over-year.

Corporate

Corporate results include (i) costs of support services such as treasury, finance, internal audit, legal, people services, enterprise risk management, asset management, and environment, health and safety, and (ii) business development expenses. Cost recovery revenues are primarily intercompany revenues that are offset by interplant category transactions.

Net corporate revenues and other income for the three and six months ended June 30, 2025, were higher compared to the same period in 2024, primarily due to insurance proceeds received in 2025. Adjusted EBITDA for the three months ended June 30, 2025 was consistent with the same period in 2024 due to insurance proceeds received in 2025, and lower salary costs that resulted from a reorganization late in 2024, offset by higher share-based compensation in 2025 compared with the same period last year as a result of higher share price appreciation compared to the comparative period. Adjusted EBITDA for the six months ended June 30, 2025 was higher due to insurance proceeds received in 2025 and lower salary costs previously discussed.

Unrealized changes in fair value of commodity derivatives and emission credits

($ millions)	Three months ended June 30			
	2025	2024	2025	2024
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income[1]**		**Income before tax[1]**	
Unrealized (losses) gains on Alberta power derivatives	(156)	47	(155)	46
Unrealized (losses) gains on U.S. power derivatives	(199)	24	(143)	24
Unrealized gains (losses) on natural gas derivatives	3	(3)	45	(46)
Unrealized gains (losses) on emission derivatives	24	1	12	(5)
Unrealized losses on emission credits held for trading	-	-	(6)	(11)
	(328)	**69**	**(247)**	**8**

($ millions)	Six months ended June 30			
	2025	2024	2025	2024
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income[1]**		**Income before tax[1]**	
Unrealized (losses) gains on Alberta power derivatives	(117)	294	(116)	293
Unrealized losses on U.S. power derivatives	(112)	(5)	(74)	(5)
Unrealized (losses) gains on natural gas derivatives	(26)	(16)	58	(62)
Unrealized losses on emission derivatives	-	(1)	(40)	(7)
Unrealized losses on emission credits held for trading	-	-	(17)	(11)
	(255)	**272**	**(189)**	**208**

[1] Revenues and other income and adjusted EBITDA from our Alberta facilities and portfolio optimization and U.S. trading include realized changes in the fair value of commodity derivatives and emission credits but exclude unrealized changes in these values. The unrealized changes are also excluded from our 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 relevant facility category.

During the three and six months ended June 30, 2025, we recognized unrealized losses on Alberta power derivatives of $155 million and $116 million, respectively, mainly due to impacts of increasing forward prices on net forward sale contracts. During the comparable periods in June 30, 2024, we recognized unrealized gains of $46 million and $293 million, respectively, mainly due to the impacts of decreasing forward prices on net forward sale contracts.

During the three and six months ended June 30, 2025, we recognized unrealized losses on U.S. power derivatives of $143 million and $74 million, respectively, mainly due to increasing forward pricing on net forward sale contracts in California, partially offset by unrealized gains on contracts at our U.S. renewable facilities. During the three months ended June 30, 2024, we recognized unrealized gains of $24 million, mainly due to the impact of decreased forward prices on forward sale contracts associated with the majority of the Company's U.S. renewables facilities and La Paloma.

During the three and six months ended June 30, 2025, we recognized unrealized gains on natural gas derivatives of $45 million and $58 million, respectively, due to impacts of increasing forward pricing on net forward buy contracts in California. During the comparable periods in June 30, 2024, we recognized unrealized losses of $46 million and $62 million, respectively, due to the impacts of decreasing pricing on forward purchase contracts.

During the six months ended June 30, 2025, we recognized unrealized losses of $40 million on emissions derivatives due to the impact of decreased forward pricing on our U.S. emissions derivatives on forward net purchases.

During the three and six months ended June 30, 2025, we recognized unrealized losses of $6 million and $17 million, respectively, on emissions credits held for trading due to the impacts of decreased forward pricing on our U.S. emissions inventory.

Consolidated other expenses and non-controlling interests

($ millions)	Three months ended June 30		Six months ended June 30	
	2025	2024	2025	2024
Net finance expense	(64)	(53)	(125)	(95)
Depreciation and amortization	(138)	(120)	(264)	(242)
Foreign exchange gain (loss)	21	(4)	23	(14)
Losses on disposals and other transactions	(6)	(17)	(7)	(15)
Other items from equity-accounted investments[1]	(36)	(34)	(73)	(59)
Income tax recovery (expense)	54	(23)	6	(100)
Net income attributable to non-controlling interests	1	1	-	1

1 Includes finance expense, depreciation expense and fair value changes on derivatives from equity-accounted investments.

Net finance expense

Higher net finance expense for the three and six months ended June 30, 2025 compared with the same periods in the prior year largely reflects higher interest due to the increased loans and borrowings outstanding from the $1.7 billion senior notes issued during 2025 (see Significant Events) and the $450 million and $600 million notes issued during the second half of 2024. This was further impacted by lower capitalized interest during 2025 due to higher construction activity for the Genesee repowering project in 2024.

Foreign exchange gain (loss)

The Company recognized foreign exchange gains for the three and six months ended June 30, 2025 due to a decrease in the USD to CAD exchange rates during the period. Comparatively, exchange rates during the period ending June 30, 2024 were increasing resulting in foreign exchange losses.

Other items from equity-accounted investments

Other items from equity-accounted investments includes Capital Power's share of finance expense, depreciation expense and unrealized changes in fair value of derivative instruments from our York Energy, Quality Wind, Port Dover and Nanticoke Wind, Midland Cogen and Harquahala equity-accounted investments. Other items from equity-accounted investments increased compared with 2024 primarily due to Quality Wind and Port Dover and Nanticoke Wind becoming equity-accounted investments upon Capital Power's partial divestiture of these assets in the fourth quarter of 2024.

Income tax expense

The Company had income tax recoveries for the three and six months ended June 30, 2025, compared to expenses in the corresponding periods in 2024 primarily due to lower overall consolidated net income before tax.

FINANCIAL POSITION

The following highlights changes in the consolidated statements of financial position from December 31, 2024 to June 30, 2025 were as follows:

	June 30, 2025	December 31, 2024
Assets		
Current assets	$ 1,502	$ 1,948
Non-current assets:		
Property, plant and equipment	10,961	8,061
Equity-accounted investments	1,051	1,096
Intangible assets and goodwill	650	744
Right-of-use assets	139	118
Derivative financial instruments	385	412
Government grant receivable	349	380
Deferred tax assets	31	26
Other assets	103	145
Total assets	$ 15,171	$ 12,930
Liabilities and equity		
Current liabilities	$ 1,622	$ 1,353
Non-current liabilities:		
Derivative financial instruments	548	494
Loans and borrowings	6,383	4,819
Lease liabilities	155	134
Deferred tax liabilities	870	863
Provisions	418	373
Deferred revenue and other liabilities	304	323
Total liabilities	10,300	8,359
Share capital	4,983	4,301
Deficit	(261)	(74)
Other reserves	156	349
Equity attributable to shareholders of the Company	4,878	4,576
Non-controlling interests	(7)	(5)
Total equity	4,871	4,571
Total liabilities and equity	$ 15,171	$ 12,930

Net working capital decreased from December 31, 2024 to June 30, 2025 by $715 million, mainly driven by:

- reduction in cash balances as described in Liquidity and Capital Resources,
- reclassifying the current portion of loans and borrowing from non-current,
- partly offset by deferred payments on capital project costs for the construction of Halkirk 2 Wind, and
- partially offset by decreased cash taxes payable due to lower overall consolidated net income before tax and higher tax deductions for certain capital projects.

Increased net derivative financial liabilities due to unrealized losses recognized on emissions derivatives from decreased forward pricing on net forward purchases, and unrealized losses recognized on U.S. power derivatives primarily from increasing forward pricing on net forward sales (see Unrealized changes in fair value of commodity derivatives and emissions credits), and the addition of Hummel Station and Rolling Hills spark spread swaps during the current quarter (see Significant Events).

Property, plant and equipment increased from December 31, 2024 to June 30, 2025 primarily due to the additions of the Hummel Station and Rolling Hills facilities. Intangible assets and goodwill decreased from December 31, 2024 to June 30, 2025 primarily due to amortization and the use of emissions credits for compliance purposes.

Non-current loans and borrowings increased from December 31, 2024 to June 30, 2025 due to the $1.7 billion of senior notes issued this quarter (see Significant Events).

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Six months ended June 30		
Cash inflows (outflows)	**2025**	**2024**	**Change**
Operating activities	353	470	(117)
Investing activities	(3,379)	(1,666)	(1,713)
Financing activities	2,496	105	2,391

Operating activities

Cash flows from operating activities for the six months ended June 30, 2025 were lower than the same period in 2024 mainly due to the net impact of:

- cash outflows from change in non-cash working capital most notably from an increase in trade and other receivables, higher trade and other payables in the prior year related to the Harquahala and La Paloma acquisitions in February, 2024,
- increased interest paid mainly due to increased interest on loans and borrowings, and
- partially offset by increased distributions received from equity-accounted investments.

Investing activities

Cash flows used in investing activities for the six months ended June 30, 2025 were higher than the same period in 2024 due to the acquisitions of the Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events).

Financing activities

Cash flows from financing activities for the six months ended June 30, 2025 were higher than the same period in 2024 due to the proceeds received from the $1.7 billion senior notes issued and increased share capital from the bought deal offering and private placement in the current quarter (see Significant Events) and lower repayments of loans and borrowings.

Capital expenditures and investments

($ millions)	Pre-2025 actual	Six months ended June 30, 2025 actual	Balance of 2025 estimated [1,2]	Actual or projected total [2]	Targeted completion
Repowering of Genesee 1 and 2 [3]	1,487	23	40 to 140	1,550 to 1,650	Achieved commercial operations fourth quarter of 2024 with project completion expected in the third quarter of 2025.
Halkirk 2 Wind [4]	298	8	13	319	Fourth quarter of 2025
Ontario growth projects	356	87	125	600	York and Goreway BESS in Q3 2025 East Windsor Expansion in Q2 2026
Maple Leaf Solar	12	16	45	231	First quarter of 2027
Bear Branch Solar	8	8	71	106	Fourth quarter of 2026
Hornet Solar	15	41	116	209	Third quarter of 2026
Commercial initiatives [5]	268	13	20		
Development sites and projects	63	(1)	-		
Subtotal growth projects		**195**	**430 to 530**		
Sustaining – plant maintenance		47			
Total capital expenditures [6]		**242**			
Emission credits held for compliance		16			
Capitalized interest		(21)			
Additions of property, plant and equipment and other assets		**237**			
Change in other non-cash investing working capital and non-current liabilities		192			
Purchase of property, plant and equipment and other assets, net		**429**			

[1] The Company's 2025 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 costs for the project including post-commercial operations date, subject to the dispute resolution with the contractor described under Contingent Liabilities, Other Legal Matters and Provisions.

[4] Targeted completion date is management's estimate of the timeline to commission the site subject to the Alberta Utilities Commission's release of its work suspension order that resulted from the nacelle and rotor at one of the turbines that fell from the tower in November 2024.

[5] Commercial initiatives include expected spending on various projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

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

Financing activities

See Liquidity and Capital Resources for significant changes in current quarter and year-to-date financing activities.

The Company's credit facilities consisted of:

($ millions)		At June 30, 2025			At December 31, 2024		
	Maturity timing	Total facilities	Credit facility utilization	Available	Total facilities	Credit facility utilization	Available
Committed credit facilities [1]	2030	1,500	447	1,053	1,000	-	1,000
Bilateral demand credit facilities	N/A	1,399			1,421		
Letters of credit outstanding			566			608	
		1,399	566	833	1,421	608	813
Demand credit facilities	N/A	25	-	25	25	-	25
		2,924	**1,013**	**1,911**	**2,446**	**608**	**1,838**

[1] Committed credit facilities include letters of credit, bankers' acceptances and bank loans outstanding.

At June 30, 2025, the Company terminated its $300 million unsecured club credit facility, increased the capacity of its committed credit facility from $700 million to $1.5 billion, and extended the term from 2029 to 2030. The available credit facilities provide adequate funding for ongoing development projects.

Capital Power has surety capacity to accommodate, as part of normal course of operations, the issuance of bonds for certain capital projects and contracts. At June 30, 2025 and December 31, 2024, $99 million of bonds were issued under these facilities.

Capital Power has the following corporate credit ratings which were affirmed in May 2025:

Rating Agency	Rating	Outlook	Definition
Standard and Poor's	BBB -	Stable	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.
DBRS Limited	BBB (low)	Stable	Adequate credit quality and the capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.
Fitch Ratings	BBB -	Stable	Expectation of default risk is low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity.

The above credit ratings 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.

During the second quarter of 2025, we obtained a credit rating by Fitch Ratings to support our long-term growth and broaden our access in the U.S. debt capital markets. Fitch assigned Capital Power a first-time issuer default rating of BBB- with a Stable outlook, reinforcing our investment-grade profile.

Off-statement of financial position arrangements

At June 30, 2025, Capital Power has $566 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements, and to satisfy legislated reclamation requirements and $99 million of surety bonds issued for certain capital projects and contracts.

If Capital Power were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on our financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

($ millions)	As at	
	June 30, 2025	December 31, 2024
Loans and borrowings	6,941	4,976
Lease liabilities [1]	173	151
Less cash and cash equivalents	(308)	(865)
Net debt	6,806	4,262
Share capital	4,983	4,301
Deficit and other reserves	(105)	275
Non-controlling interests	(7)	(5)
Total equity	4,871	4,571
Total capital	**11,677**	**8,833**

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

Capital Power uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital when required. Under the short-form base shelf prospectus dated June 12, 2024, Capital Power may issue an unlimited number of common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of Capital Power and/or debt securities, including up to $3 billion of medium-term notes by way of a prospectus supplement. This prospectus expires in July 2026.

If the Canadian and U.S. financial markets become unstable, Capital Power's ability to raise new capital, to meet our 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 our power purchase agreement, energy supply contract, trading and supplier counterparties. While Capital Power continues to monitor our exposure to 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 and Capital Power's risk mitigation strategies.

CONTINGENT LIABILITIES, OTHER LEGAL MATTERS AND PROVISIONS

Refer to the Contractual Obligations, Contingent Liabilities, Other Legal Matters and Provisions discussion in our 2024 Integrated Annual Report for details on ongoing legal matters.

Contingent liabilities

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

A dispute arose in 2024 between the Company and the contractor regarding construction work on the Genesee Repowering Project. The parties are participating in an arbitration process to resolve the claims by both parties. The Company has withheld payments pending the resolution of the dispute. Preliminary matters related to the arbitration process began late in the second quarter of 2025.

RISKS AND RISK MANAGEMENT

For the six months ended June 30, 2025, Capital Power's business, operational and climate-related risks and opportunities have remained consistent with those described in our 2024 Integrated Annual Report other than risks around tariffs imposed by the U.S. and Canada. See Regulatory and Government Matters for management's assessment of the impact of these tariffs. Future changes to tariffs imposed by both the U.S. and Canada may materially change management's current assessment.

Details around Capital Power's approach to risk management, including principal risk factors and the associated risk mitigation strategies, are described in our 2024 Integrated Annual Report. These factors and strategies have not changed materially in the six months ended June 30, 2025.

In addition, the Company's acquisition of the Hummel Station and Rolling Hills facilities, expands the Company's operations into the PJM Interconnection market and presents new operational and market risks.

Market Exposure to the Hummel Station and Rolling Hills facilities

In PJM, the day-ahead and real-time markets are nodal markets which are based on the supply and demand of the energy market as a whole and of each individual node on the grid, taking into account the physical constraints of the transmission system. As a result, the nodal market incorporates local losses and congestion into the price that generators receive, exposing assets to basis risk compared to the major hub and/or zonal prices where hedges are typically available. Additionally, participants in the PJM capacity market must commit to being available to supply capacity or reduce demand in the energy market. However, there is no guarantee that the Hummel Station and Rolling Hills facilities will have the required capacity when needed the most, exposing them to potential penalties for non-performance if they fail to meet their commitments during periods of grid system stress or emergencies.

Merchant markets are cyclical and there is risk that future merchant revenues fall short of expectations. Given the current increase in capacity prices, PJM is making efforts to dampen capacity prices going forward, including but not limited to, proposing a lower price cap in future capacity auctions. Merchant exposure risk can be mitigated for resource adequacy through advanced contracting and risk on energy margin can be mitigated through heat rate call options and other products. Risk mitigation steps may shift risk from merchant energy to other risks, such as gas basis or operational risks. However, there remains a risk that future PJM market rule changes may not allow operators, including Capital Power with respect to the Hummel Station and Rolling Hills facilities, to earn market-based returns.

The PJM BRA results for the 2026/2027 year were posted on July 22, 2025 (see Significant Events). While the Hummel Station facility and the four operational units at the Rolling Hills facility are currently capable of meeting their capacity commitments, unforeseen circumstances may prevent the facilities from meeting their future capacity commitments (see Regulatory and Government Matters – PJM market).

ENVIRONMENTAL MATTERS

Capital Power recorded decommissioning provisions of $367 million at June 30, 2025 ($346 million at December 31, 2024) for our 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 were incurred over time as new areas were 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.

At June 30, 2025, Capital Power has forward contracts to purchase environmental credits totaling $1,330 million and forward contracts to sell environmental credits totaling $1,094 million in future years. Included within these forward purchases and sales are net purchase amounts which will be used to comply with applicable environmental regulations and net sale amounts related to other emissions trading activities.

REGULATORY AND GOVERNMENT MATTERS

Refer to the Regulatory Matters discussion in the Company's 2024 Integrated Annual Report for further details that supplement the recent developments discussed below:

United States

U.S. Clean Air Act

In June 2025, the Environmental Protection Agency (EPA) released a draft rule that would repeal all greenhouse gas (GHG) standards for fossil fuel electric generating units, effectively kicking off a rulemaking process to overturn a previous rule that aimed to curb GHG emissions for coal-, gas-, and oil-fired power plants. This decision, once finalized, will remove the federal requirement for Capital Power to decarbonize future expansions to our thermal fleet. Given the need for notice and comment, and the statutory time period for states to develop implementation plans for existing sources under the Clean Air Act, it is unlikely that existing gas units will face CO2 regulation until the early- to mid-2030s at the earliest from the U.S. federal government.

Maricopa County, Arizona, where the Arlington Valley and Harquahala natural gas facilities are located, does not meet the National Ambient Air Quality Standards set by the EPA under the Clean Air Act for two of the six principal pollutants. Maricopa County is currently classified as “moderate” nonattainment levels for these principal pollutants, and a reclassification to “serious” nonattainment levels can occur any time after February 3, 2025, which would result in changes in permitting requirements for existing, new and modified principal pollutants. Maricopa County was previously facing additional offset sanctions at a 2:1 level for failure to submit a plan to EPA addressing moderate level air quality requirements, but an agreement was reached with EPA in the second quarter of 2025 that a sufficient moderate level plan was received, thus halting the threat of additional 2:1 sanctions. If Maricopa County continues to remain in nonattainment status, Capital Power will be challenged to construct additional turbines at Arlington Valley and Harquahala without offsetting emissions. Management continues to monitor developments.

U.S. tariffs

During the first quarter of 2025, President Trump issued tariffs which have created economic and political uncertainties, such as potential counter tariffs from other countries, including those imposed by the Government of Canada and Government of Ontario. Management has consulted external legal counsel and assessed potential scenarios under President Trump’s tariff announcements that could impact the Company’s operations, specifically Canadian electricity sales to the U.S., and the sales of renewable energy certificates from Canada to the U.S. While at this time, we do not expect significant impacts to Capital Power, this is an evolving risk that may impact future supply chain costs and sales of power to the U.S. Management will continue to monitor the situation as changes to the tariff framework are put into place.

One Big Beautiful Bill (OBBB)

The US Congress approved a budget reconciliation bill known as the One Big Beautiful Bill (OBBB) that seeks to reauthorize the tax cuts from the 2017 Tax Cuts and Jobs Act, which President Donald Trump signed into law on July 4, 2025. To pay for the cost of reauthorization, members of Congress are seeking cuts to other tax provisions including the clean energy investment tax credit and production tax credit that were authorized in the 2022 Inflation Reduction Act. The bill language requires a clean energy project to commence construction within one year of enactment to claim 100% of the existing tax credit benefits, and a placed in-service date of December 31, 2027, to be eligible. There are also requirements on the percentage of a component, subcomponent, or critical mineral used in the project to be sourced domestically or from countries that are not considered foreign entities of concern.

Capital Power projects that are included in the scope of this legislation are Maple Leaf Solar, Bear Branch Solar, and Hornet Solar in North Carolina; Greencastle in Indiana; and Nolin Hills in Oregon. Capital Power will be required to commence construction of a solar facility within 12 months of enactment and to place into service by 2027 in order to benefit from the current clean energy tax credit benefits. Management will continue to monitor and evaluate how this change will impact renewables growth projects currently underway.

New Jersey legislation

In March 2025, legislation was proposed that would alter the New Jersey’s Board of Public Utilities (BPU) solar renewable energy certificate (SREC) program and ultimately reduce the cost of the Solar Alternative Compliance Payment (SACP) required to be paid by electricity suppliers to satisfy their renewable energy supply requirements. A week after the introduction of the initial legislation, an additional bill proposing changes to the Legacy SREC Program was introduced in the Senate. The bill proposes to eliminate New Jersey’s solar renewable energy portfolio standards commencing on June 1, 2025.

Capital Power’s trading desk has long term financial projections that assume this program stays in place. The market dipped sharply immediately after the bill introduction but has since stabilized at levels slightly below those observed prior to the bill introduction. The General Assembly met on May 15, 2025, to discuss the bill but no further action has been taken. Management will continue to monitor bill status and further attempts to change the SREC program.

Pennsylvania regulatory environment

Pennsylvania does not currently price carbon, but there are ongoing discussions at the state level about implementing carbon pricing. The state's previous governor attempted to join the Regional Greenhouse Gas Initiative (RGGI), a program aimed at reducing carbon emissions from the power sector in several northeastern and mid-Atlantic states, through an executive action. However, this effort was overturned by the courts as an unconstitutional tax. An alternative, made-in-Pennsylvania program, the Pennsylvania Climate Emissions Reduction Act (PACER), has been proposed. This program would allow Pennsylvania to retain control over the emissions cap and the auction process. Characterized as a "Cap-and-Invest" program, PACER is intended to keep revenue in Pennsylvania, with 70% of the proceeds being returned to consumers as rebates, and 30% invested in energy efficiency projects, clean energy initiatives, and support for low-income energy consumers. Management will continue to monitor this situation for further developments.

PJM market

PJM is a regional transmission organization that dispatches generation, operates a competitive wholesale electricity market and manages the reliability of a transmission grid spanning all or parts of 13 states and the District of Columbia, serving more than 65 million people. PJM is the largest centrally operating market in North America, with approximately 200 GW of installed capacity and peak demand of approximately 150 GW. PJM is currently experiencing substantial population growth and industrial development, including growth in data centre energy consumption, driven by the rapid expansion of digital infrastructure. The Company expects higher energy and capacity prices across PJM footprints due to load growth alone. According to PJM's 2025 load forecast, peak demand is expected to grow at annualized rates above 3% in the next ten years.

In PJM, both the day-ahead and real-time markets are nodal markets, where electricity prices are determined based on the supply and demand at each individual node on the grid, considering both the supply and demand as well as the physical constraints of the transmission system. In addition to its wholesale market, PJM operates a capacity market through the Reliability Pricing Model, which focuses on securing sufficient long-term resources to ensure grid reliability. PJM generally holds an annual BRA for capacity resources to meet expected energy demand needs for the future capacity year three years in advance; however, this schedule has been compressed due to delays beginning in 2019 around the Federal Energy Regulatory Commission’s (FERC) Minimum Offer Price Rule and further delays in the wake of Winter Storm Elliot exposing vulnerabilities to PJM's reliability, causing PJM to reform its auction rules. The auctions are currently expected to be held every six months until PJM is back on the three-year forward schedule by May 2027. PJM has instituted a maximum capacity price of US$325/Megawatt-day (MWd) and a minimum capacity price of US$175/MWd for the next two auctions to increase market stability. When participants offer resources into the auction, they are committing to be available to supply capacity or reduce demand in the energy market. If participants fail to meet these commitments during periods of grid system stress or emergencies, they face penalties for non-performance. If participants are on-line at full bid capacity during periods of grid system stress or emergency, they can earn incentives.

Annually, PJM performs a review of the capital additions required to provide reliable electric transmission services throughout its territory. PJM traditionally allocated the costs of constructing these facilities to those entities that benefited directly from the additions. Over the last several years, however, some of the costs of constructing large, new transmission facilities have been socialized across PJM without a direct relationship between the costs assigned to and benefits received by particular PJM members. To the extent that any costs in the future are material and Capital Power is unable to recover them, such costs could have a material adverse effect on our results of operations, financial condition and cash flows.

PJM market is under pressure from various stakeholders including state consumer advocates, elected officials and public interest organizations to alleviate reliability and affordability concerns. If government officials at the state or federal level determine that market reform is needed to alleviate reliability and affordability concerns, then increased oversight over FERC, and by extension PJM, could facilitate or accelerate changes in market structures, potentially favouring state-driven procurement models over centralized capacity auctions. This could disrupt competitive market dynamics and create uncertainty for market participants.

Canada

Alberta

Alberta Electric System Operator (AESO) Restructured Energy Market (REM)

On March 11, 2024, the GoA and the AESO announced plans to restructure the energy market to address long-term reliability, affordability, and decarbonization objectives. Over the course of 2024, the AESO consulted on high-level design. On April 4, 2025, the AESO shared that it is refining the REM design to simplify the implementation and that it will no longer be pursuing day ahead energy and commitment markets as part of the design. The AESO also pivoted on key pricing parameters, indicating that the offer cap will increase from the current level of $999.99/MWh and the price cap will increase to $3,000/MWh at times of scarcity. The AESO also indicated that its preferred approach to manage congestion is through the introduction of locational marginal pricing.

On May 22, 2025, the AESO published further details of their revised high level design including details of the day-ahead reliability market for operating reserves, a reliability unit commitment mechanism, a new 30-minute real-time ramping product (R30) with an associated administrative demand curve and proposed details for broad and local market power mitigation. The AESO’s high-level design indicated that at the onset of REM, the offer cap will increase to $1,500/MWh and in 2032 increase further to $2,000/MWh while the floor will drop from $0/MWh to -$100/MWh over the same period. The AESO held final high level design consultations during June 2025 and is anticipated to put forward its design later this year at which point detailed rules consultation will begin. The REM is still anticipated to be implemented in 2027. Management will continue to participate in the AESO’s consultation and will assess more detailed design and rule impacts as they become available.

Alberta Bill 52 – Energy and Utilities Statutes Amendment Act, 2025

On May 12, 2025, the GoA passed the Energy and Utilities Statutes Amendment Act to enable the AESO to implement the REM. The Act makes necessary changes to the rules approval process to allow the REM rules to be enacted by the Minister through regulation (instead of the Alberta Utilities Commission). The bill also removes the congestion free policy from the AESO's policy obligations for transmission planning. Other changes in the Act remove barriers to allow hydrogen blending in the natural gas distribution system for residential and commercial heating to support new technologies while ensuring the safety and reliability of the system; and streamline the process to connect with other jurisdictions, reducing red tape and enabling critical improvements.

Connection for large load projects in Alberta

On June 4, 2025, the AESO shared details on Phase 1 of their large load connection plan, updating industry with details on how data centre projects in Alberta will be provided with an opportunity to connect to the grid. For Phase 1, the AESO will instate a 1,200 MW interim connection limit that will be allocated to qualified data centre projects. In addition to Phase 1, the AESO also communicated that it will begin engagement for a long-term framework for connecting large load projects sometime in the second half of 2025.

Management is actively following developments in all matters related to large load interconnection and will continue to work with the AESO and other stakeholders to progress data centre development in the province.

AESO Independent Systems Operator (ISO) tariff redesign

On March 5, 2025, the AESO kicked off an engagement to redesign its ISO tariff, which outlines the rates, terms and conditions for market participants who receive access to the transmission system. The scope of the engagement will include addressing ancillary service cost allocation, system access charges for generators and amendments to the connection process with a filing with the Alberta Utilities Commission (AUC) in 2026; and demand rates, tariffs for imports and exports, and additional considerations are to be filed with the Commission in 2027. New rates are expected to take effect in 2029 following the AUC review process. Management will participate as appropriate in the AESO’s engagement over the next two years.

Optimal transmission planning (OTP)

Following the Alberta government’s July 2024 policy direction to shift from a zero-congestion to an OTP standard, the AESO launched stakeholder engagement in the second quarter of 2025. Management participated in two AESO-led sprints which focused on refining the OTP framework and introduced the Transmission Reinforcement Payment (TRP), which is intended to replace the Generating Unit Owner’s Contribution (GUOC) – an upfront payment made by generators to fund transmission infrastructure. As part of this engagement, the AESO has been consulting on financial transmission rights to hedge congestion risk with the move to LMP. Management anticipates further details will be made available later this year as rule drafting is expected before year-end. Management will continue to participate in this process.

AESO ISO Fast Frequency Response Plus (FFR+) procurement

In June 2025, the AESO launched a new engagement on FFR+, a proposed ancillary service designed to support full import flows on Alberta’s BC and Montana interties. FFR+ builds on the existing Fast Frequency Response framework by incorporating additional non-market reliability services such as system strength, fast net demand response, and blackstart capability. Management is registered to participate in a late July stakeholder session and will continue to monitor and engage as the AESO refines the product and procurement design ahead of the anticipated request for proposals (RFP) release in mid-2026.

Ontario

Market Renewal Program (MRP)

The Independent Electricity System Operator’s (IESO’s) MRP is a set of coordinated market and IESO system reforms intended to improve market transparency, competitiveness, and real-time unit scheduling. It will introduce locational marginal pricing, market power mitigation, and a financially binding day-ahead market. The MRP market rule amendments were approved by the IESO Board on October 18, 2024. The IESO transitioned to the new market on May 1, 2025. Management is now monitoring the impact the MRP has on the Company’s generating contracts and continues to work with the IESO to minimize any adverse outcomes. Management may, if necessary, leverage provisions within the contracts that are intended to protect suppliers from adverse effects resulting from market rule changes.

Ontario Bill 40 – Protect Ontario by Securing Affordable Energy for Generations Act, 2025

On June 3, the Ontario government tabled legislation to support major growth in Ontario's energy system to meet rising demand. The legislation is proposed to enable the IESO and the Ontario Energy Board (OEB) to prioritize projects that promote economic growth and create jobs, support made-in-Canada energy technology for security and increase support for hydrogen. Management will continue to monitor changes and opportunities resulting from the legislation and the subsequent integrated energy plan.

Ontario's integrated energy plan

On June 12, 2025, Ontario released the province's inaugural integrated energy plan titled "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7". The plan builds on energy policy and key initiatives including energy efficiency, Indigenous partnerships, and affordable, secure, reliable, and clean electricity. The plan also consolidates broad energy policy goals around Ontario becoming an energy superpower, streamlining permitting of large-scale energy infrastructure projects, and continued support for investment in nuclear and transmission. The plan further reaffirms the critical role natural gas plays in Ontario's energy system and the government's commitment to the IESO's competitive procurements for electricity generation. Management will continue to monitor changes and opportunities resulting from the integrated energy plan and related legislation.

USE OF JUDGMENTS AND ESTIMATES

In preparing the condensed interim consolidated financial statements, management made judgments, estimates and assumptions that affect the application of Capital Power'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 Capital Power's use of judgments and estimates as described in our 2024 Integrated Annual Report.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at June 30, 2025 and December 31, 2024 were as follows:

($ millions)		June 30, 2025		December 31, 2024	
	Fair value hierarchy level [1]	**Carrying amount**	**Fair value**	**Carrying amount**	**Fair value**
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	308	308	865	865
Trade and other receivables [2]	N/A	684	684	546	546
Government grant receivable [3]	Level 2	434	403	438	400
Fair value through profit or loss					
Derivative financial instruments [3]	See below	605	605	601	601
Fair value through other comprehensive income					
Derivative financial instruments [3]	See below	36	36	55	55
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	626	626	751	751
Loans and borrowings [3]	Level 2	6,941	7,197	4,976	5,244
Fair value through profit or loss					
Derivative financial instruments [3]	See below	789	789	621	621
Fair value through other comprehensive income					
Derivative financial instruments [3]	See below	24	24	20	20

[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. Level 3 valuations are determined by appropriate subject matter experts and reviewed by the Company's commodity risk group and by management.

[2] Includes income taxes recoverable and excludes current portion of government grant receivable.

[3] Includes current and non-current portion.

Risk management and hedging activities

There have been no material changes in the six months ended June 30, 2025 to our risk management and hedging activities as described in our 2024 Integrated Annual Report.

The derivative financial instruments assets and liabilities held at June 30, 2025 compared with December 31, 2024 and used for risk management purposes were measured at fair value and consisted of the following:

($ millions)		At June 30, 2025					
	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	30	487	7	-	-	524
	Level 3	-	117	-	-	-	117
		30	604	7	-	-	641
Derivative financial instruments liabilities	Level 2	(6)	(511)	(19)	(1)	-	(537)
	Level 3	-	(276)	-	-	-	(276)
		(6)	(787)	(19)	(1)	-	(813)
Net derivative financial instruments assets (liabilities)		**24**	**(183)**	**(12)**	**(1)**	**-**	**(172)**

($ millions)		At December 31, 2024				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Foreign exchange cash flow hedges**	**Total**
Derivative financial instruments assets	Level 2	45	465	4	6	520
	Level 3	-	136	-	-	136
		45	601	4	6	656
Derivative financial instruments liabilities	Level 2	(4)	(329)	(16)	-	(349)
	Level 3	-	(292)	-	-	(292)
		(4)	(621)	(16)	-	(641)
Net derivative financial instruments assets (liabilities)		**41**	**(20)**	**(12)**	**6**	**15**

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

Unrealized gains and losses from fair value changes on commodity, interest rate and foreign exchange derivatives that qualify and are elected for hedge accounting are recorded in other comprehensive income (loss). When realized, they are reclassified to net income as revenues, energy purchases and fuel, finance expense or foreign exchange gains and losses as appropriate. For interest rate derivatives 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. For foreign exchange derivatives hedging cash flow variability from foreign currency fluctuations on future capital expenditures, realized gains and losses are also deferred within accumulated other comprehensive income (loss) and then recorded in property, plant and equipment and amortized through depreciation and amortization over the hedged asset's estimated useful life.

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 power, natural gas and REC prices and their impact within the Canada and U.S. flexible generation and renewables portfolios. 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

With the exception of the acquisitions of Hummel Station and Rolling Hills (see Significant Events), which are being integrated into Capital Power's systems of internal controls, there were no significant changes in Capital Power's disclosure controls and procedures and internal controls over financial reporting that occurred during the six months ended June 30, 2025 that have materially affected or are reasonably likely to materially affect disclosures of required information and internal control over financial reporting.

In accordance with National Instrument 52-109, management's evaluation of and conclusions on the effectiveness of internal control over financial reporting did not include the internal controls of the acquired businesses of Hummel Station, LLC and Rolling Hills Generating LLC. The financial results are included in the Company's June 30, 2025 consolidated financial statements because these entities were acquired by the Company through a business combination during the second quarter of 2025. The aggregate assets represent 20% of the Company's total assets as at June 30, 2025, and the aggregate liabilities represent 1% of the Company's total liabilities as at June 30, 2025. Gross revenue earned from the date of acquisition to June 30, 2025, represents 4% of the Company's gross revenue for the quarter ended June 30, 2025.

SUMMARY OF QUARTERLY RESULTS

	Three months ended							
	Jun 2025	**Mar 2025**	**Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	**Dec 2023**	**Sep 2023**
Electricity generation (GWh)								
Canada flexible generation	3,933	4,799	3,596	4,518	3,417	4,445	4,312	4,641
Canada renewables	557	597	704	541	696	676	742	514
U.S. flexible generation	4,026	3,575	4,540	5,574	3,909	3,116	3,066	3,006
U.S. renewables	506	584	568	368	581	572	572	360
Total electricity generation	9,022	9,555	9,408	11,001	8,603	8,809	8,692	8,521
Facility availability (%)								
Canada flexible generation	91	94	87	93	88	93	95	97
Canada renewables	97	96	96	95	97	95	95	94
U.S. flexible generation	96	85	88	96	93	94	89	98
U.S. renewables	89	90	93	88	92	92	95	93
Total average facility availability	93	90	89	94	91	94	93	96
Revenues and other income ($ millions)								
Canada flexible generation	472	580	523	520	473	677	666	761
Canada renewables	28	30	56	43	54	61	70	50
U.S. flexible generation	213	250	198	286	138	135	84	88
U.S. renewables	37	41	37	31	38	40	39	33
Corporate[1]	19	14	9	5	2	3	27	35
Unrealized changes in fair value of commodity derivatives and emission credits	(328)	73	30	145	69	203	98	183
Total revenues and other income	**441**	**988**	**853**	**1,030**	**774**	**1,119**	**984**	**1,150**
Adjusted EBITDA [2]								
Canada flexible generation[3]	166	207	200	187	163	179	209	256
Canada renewables[3]	27	33	42	27	41	44	56	30
U.S. flexible generation[3]	141	119	123	219	128	84	46	109
U.S. renewables	27	31	26	19	29	28	29	21
Corporate	(39)	(23)	(61)	(51)	(38)	(46)	(24)	(2)
Total adjusted EBITDA[2]	**322**	**367**	**330**	**401**	**323**	**289**	**316**	**414**

1 Revenues are partly offset by interplant category revenue eliminations.

2 Adjusted EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures and Ratios.

3 Canada flexible generation includes adjusted EBITDA from York Energy joint venture. Canada renewables include adjusted EBITDA from Quality Wind and Port Dover and Nanticoke Wind joint ventures. U.S. flexible generation includes adjusted EBITDA from Midland Cogen and Harquahala joint ventures.

Financial highlights

($ millions except per share amounts)	Three months ended							
	Jun 2025	Mar 2025	Dec 2024	Sep 2024	Jun 2024	Mar 2024	Dec 2023	Sep 2023
Revenues and other income	441	988	853	1,030	774	1,119	984	1,150
Adjusted EBITDA [1, 2]	322	367	330	401	323	289	316	414
Net (loss) income	(131)	150	242	178	76	205	95	272
Net (loss) income attributable to shareholders of the Company	(132)	151	240	179	75	205	97	274
Basic (loss) earnings per share ($)	(0.92)	1.03	1.76	1.32	0.51	1.58	0.74	2.27
Diluted (loss) earnings per share ($)[3]	(0.92)	1.03	1.75	1.32	0.51	1.57	0.74	2.26
Net cash flows from (used in) operating activities	143	210	438	236	136	334	(18)	480
AFFO [1]	235	218	182	315	178	149	165	296
AFFO per share ($) [1]	1.55	1.57	1.38	2.42	1.37	1.21	1.39	2.53
Purchase of property, plant and equipment and other assets, net	141	288	395	231	226	218	244	262

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

2 Includes adjusted EBITDA from the York Energy, Midland Cogeneration and Harquahala equity-accounted investments. Quality Wind and Port Dover and Nanticoke Wind were partially divested on December 20, 2024, and then became equity-accounted investments (see Significant Events in the Company's 2024 Integrated Annual Report). Due to the proximity to December 31, 2024, adjusted EBITDA relating to the equity-accounted investments period during the quarter was immaterial.

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

	Three months ended							
Spot price averages	Jun 2025	Mar 2025	Dec 2024	Sep 2024	Jun 2024	Mar 2024	Dec 2023	Sep 2023
Alberta power ($ per MWh)	40	40	52	55	45	99	82	152
Alberta natural gas (AECO) ($ per GJ)	1.64	2.03	1.45	0.65	1.14	1.94	2.19	2.49
Capital Power's Alberta portfolio average realized power price ($ per MWh)	72	73	78	74	78	82	84	93

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, 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 our power, natural gas, interest rate and foreign exchange derivative contracts.

Factors impacting results for the previous quarters

Please refer to our 2024 Integrated Annual Report for significant events and items which affected results for the previous quarters.

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							
	Jun 2025	Mar 2025	Dec 2024	Sep 2024	Jun 2024	Mar 2024	Dec 2023	Sep 2023
Share price ($/common share)								
High	57.92	64.95	68.73	50.88	41.99	39.43	39.88	42.34
Low	41.87	44.68	49.20	38.33	33.90	35.55	35.11	37.84
Close	54.80	47.83	63.72	49.17	38.99	38.21	37.84	37.92
Volume of shares traded (millions)	48.7	59.2	38.0	28.3	33.5	25.9	26.0	18.6

Outstanding share and partnership unit data

At July 25, 2025, the Company had 155.110 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), and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares at July 25, 2025 were 156.462 million. The outstanding special limited voting share is held by EPCOR.

At July 25, 2025, CPLP had 323.305 million general partnership units outstanding and 1,203.255 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.sedarplus.com.

Condensed Interim Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)
Six months ended June 30, 2025 and 2024

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Six months ended June 30, 2025 and 2024

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2025	Three months ended June 30, 2024	Six months ended June 30, 2025	Six months ended June 30, 2024
Revenues	$ 407	$ 753	$ 1,362	$ 1,850
Other income	34	21	67	43
Energy purchases and fuel	(260)	(360)	(749)	(886)
Gross margin	181	414	680	1,007
Other raw materials and operating charges	(53)	(51)	(106)	(97)
Staff costs and employee benefits expense	(53)	(50)	(94)	(99)
Depreciation and amortization	(138)	(120)	(264)	(242)
Other administrative expense	(89)	(43)	(134)	(99)
Foreign exchange gain (loss)	21	(4)	23	(14)
Operating (loss) income	(131)	146	105	456
Net finance expense (note 4)	(64)	(53)	(125)	(95)
Income from equity-accounted investments	16	23	40	35
Losses on disposals and other transactions	(6)	(17)	(7)	(15)
(Loss) income before tax	(185)	99	13	381
Income tax recovery (expense) (note 5)	54	(23)	6	(100)
Net (loss) income	$ (131)	$ 76	$ 19	$ 281
Attributable to:				
Non-controlling interests	$ 1	$ 1	$ -	$ 1
Shareholders of the Company	$ (132)	$ 75	$ 19	$ 280

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

	Three months ended June 30, 2025	Three months ended June 30, 2024	Six months ended June 30, 2025	Six months ended June 30, 2024
Basic (note 6)	$ (0.92)	$ 0.51	$ 0.03	$ 2.06
Diluted (note 6)	$ (0.92)	$ 0.51	$ 0.03	$ 2.06

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2025	Three months ended June 30, 2024	Six months ended June 30, 2025	Six months ended June 30, 2024
Net (loss) income	$ (131)	$ 76	$ 19	$ 281
Other comprehensive (loss) income:				
Items that may be reclassified subsequently to net income:				
Unrealized (losses) gains on derivative instruments[1] (note 7)	(4)	20	6	90
Reclassification of gains on derivative instruments to net income[2] (note 7)	(9)	(11)	(18)	(8)
Equity-accounted investments[3]	(2)	1	(6)	6
Net investment in foreign subsidiaries:				
Unrealized (losses) gains	(173)	29	(175)	68
Other comprehensive (loss) income for the period, net of tax	(188)	39	(193)	156
Total comprehensive (loss) income	$ (319)	$ 115	$ (174)	$ 437
Attributable to:				
Non-controlling interests	$ 1	$ 1	$ -	$ 1
Shareholders of the Company	$ (320)	$ 114	$ (174)	$ 436

[1] For the three and six months ended June 30, 2025, net of income tax (recovery) expense of $(1) and of $3, respectively. For the three and six months ended June 30, 2024, net of income tax expense of $5 and of $18, respectively.

[2] For the three and six months ended June 30, 2025, net of reclassification of income tax expense of $2 and $5, respectively. For the three and six months ended June 30, 2024, net of reclassification of income tax expense of $3 and $2, respectively.

[3] For the three and six months ended June 30, 2025, net of income tax recovery of $1 and $2, respectively. For the three and six months ended June 30, 2024, net of income tax expense of $2 and $3, 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)

	June 30, 2025	December 31, 2024
Assets		
Current assets:		
Cash and cash equivalents	$ 308	$ 865
Trade and other receivables	575	507
Income taxes recoverable (note 5)	159	97
Inventories	204	235
Derivative financial instruments (note 7)	256	244
	1,502	1,948
Non-current assets:		
Property, plant and equipment (note 3)	10,961	8,061
Equity-accounted investments	1,051	1,096
Intangible assets and goodwill	650	744
Right-of-use assets	139	118
Derivative financial instruments (note 7)	385	412
Government grants receivable	349	380
Deferred tax assets	31	26
Other assets	103	145
Total assets	$ 15,171	$ 12,930
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 626	$ 751
Derivative financial instruments (note 7)	265	147
Loans and borrowings (note 8)	558	157
Provisions	69	85
Deferred revenue and other liabilities	104	213
	1,622	1,353
Non-current liabilities:		
Derivative financial instruments (note 7)	548	494
Loans and borrowings (note 8)	6,383	4,819
Lease liabilities	155	134
Deferred tax liabilities	870	863
Provisions	418	373
Deferred revenue and other liabilities	304	323
Total liabilities	10,300	8,359
Share capital (note 9)	4,983	4,301
Deficit	(261)	(74)
Other reserves	156	349
Equity attributable to shareholders of the Company	4,878	4,576
Non-controlling interests	(7)	(5)
Total equity	4,871	4,571
Total liabilities and equity	$ 15,171	$ 12,930

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Share capital (note 9)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Balance, January 1, 2025	$ 4,301	$ 108	$ 240	$ (9)	$ 10	$ (74)	$ 4,576	$ (5)	$ 4,571
Net income	-	-	-	-	-	19	19	-	19
Other comprehensive loss	-	(18)	(175)	-	-	-	(193)	-	(193)
Total comprehensive (loss) income	-	(18)	(175)	-	-	19	(174)	-	(174)
Issue of share capital, net[2]	648	-	-	-	-	-	648	-	648
Common share dividends (note 9)	-	-	-	-	-	(192)	(192)	-	(192)
Preferred share dividends, net of tax[3] (note 9)	-	-	-	-	-	(14)	(14)	-	(14)
Dividends reinvested	34	-	-	-	-	-	34	-	34
Distributions to non-controlling interests	-	-	-	-	-	-	-	(2)	(2)
Balance, June 30, 2025	$ 4,983	$ 90	$ 65	$ (9)	$ 10	$ (261)	$ 4,878	$ (7)	$ 4,871

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

[2] Net of share issue costs of $28, income tax recovery of $7, and share options exercised of $2.

[3] Including income tax expense of $1.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Share capital (note 9)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Balance, January 1, 2024	$ 3,524	$ 48	$ 22	$ (10)	$ 10	$ (404)	$ 3,190	$ (4)	$ 3,186
Net income	-	-	-	-	-	280	280	1	281
Other comprehensive income	-	88	68	-	-	-	156	-	156
Total comprehensive income	-	88	68	-	-	280	436	1	437
Issue of share capital, net[2]	387	-	-	-	-	-	387	-	387
Common share dividends (note 9)	-	-	-	-	-	(159)	(159)	-	(159)
Preferred share dividends, net of tax[3] (note 9)	-	-	-	-	-	(19)	(19)	-	(19)
Dividends reinvested	33	-	-	-	-	-	33	-	33
Share options exercised	10	-	-	-	-	-	10	-	10
Distributions to non-controlling interests	-	-	-	-	-	-	-	(2)	(2)
Balance, June 30, 2024	$ 3,954	$ 136	$ 90	$ (10)	$ 10	$ (302)	$ 3,878	$ (5)	$ 3,873

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.

2 Net of share issue costs of $16 and income tax recovery of $3.

3 Including income tax expense of $1.

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)

	Six months ended June 30, 2025	2024
Cash flows from operating activities:		
Net income	$ 19	$ 281
Non-cash adjustments:		
Depreciation and amortization	264	242
Net finance expense	125	95
Fair value changes on commodity derivative instruments and emission credits held for trading	189	(208)
Foreign exchange (gains) losses	(23)	14
Income tax (recovery) expense	(6)	100
Income from equity-accounted investments	(40)	(35)
Tax-equity attributes	(42)	(40)
Other	14	-
Change in fair value of derivative instruments, cash settlement	(7)	19
Distributions received from equity-accounted investments	38	11
Interest paid	(115)	(59)
Income taxes recovered (paid)	3	(20)
Other	(12)	-
Change in non-cash operating working capital	(54)	70
Net cash flows from operating activities	353	470
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets, net[1]	(429)	(444)
Business acquisition, net of acquired cash (note 3)	(2,973)	(908)
Acquisition of equity-accounted investment	-	(316)
Government grant received	10	-
Other	13	2
Net cash flows used in investing activities	(3,379)	(1,666)
Cash flows from in financing activities:		
Net proceeds from issue of loans and borrowings[2] (note 8)	2,091	445
Repayment of loans and borrowings	(42)	(155)
Capitalized interest paid	(21)	(30)
Issue of share capital[3]	641	1
Dividends paid (note 9)	(161)	(137)
Income taxes paid on preferred share dividends	(5)	(7)
Other	(5)	(10)
Distributions to non-controlling interests	(2)	(2)
Net cash flows from financing activities	2,496	105
Foreign exchange loss on cash held in a foreign currency	(27)	-
Net decrease in cash and cash equivalents	(557)	(1,091)
Cash and cash equivalents, beginning of period	865	1,423
Cash and cash equivalents, end of period	$ 308	$ 332

1 Reflects total additions, increased by $192 for changes in non-cash investing working capital and other non-current assets and liabilities (2024 – reduced by $77), to arrive at cash additions of property, plant and equipment and other assets.

2 Net of deferred debt issue costs of $14 (2024 - $5).

3 Net of share issue costs of $28 (2024 - $8).

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns, and operates utility-scale renewable and flexible generation (natural gas generation assets and energy storage) 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 and use of judgements and estimates

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 2024 annual consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS) Accounting Standards as issued by the International Accounting Standards Board.

The accounting policies applied, the significant judgements made, and the key sources of estimation uncertainty are consistent with those described in the Company’s 2024 annual consolidated financial statements, except as described in note 11.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on July 29, 2025.

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

3. Business combination

Acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC

On June 9, 2025, the Company acquired 100% of the equity interests in:

1. Hummel Station, LLC, owner of the 1,124 megawatt (MW) Hummel Station combined-cycle natural gas facility in Shamokin Dam, Pennsylvania; and
2. Rolling Hills Generating, LLC, owner of the 1,023 MW Rolling Hills Generation plant, a combustion turbine natural gas facility in Wilkesville, Ohio.

The acquisition expands the Company's operations into the Pennsylvania-New Jersey-Maryland Interconnection market and adds to its U.S. flexible generation fleet.

The total purchase price of the acquisition was $3.0 billion (US$2.2 billion) in total cash consideration, including working capital and other closing adjustments, which are expected to be finalized in the second half of 2025.

The valuation techniques used for measuring the fair value of material assets acquired include significant estimates associated with the depreciated replacement cost approach for property, plant and equipment, which includes estimates of replacement cost and reflects adjustments for physical deterioration as well as functional and economic obsolescence.

The preliminary allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values was as follows:

	June 9, 2025
Cash and cash equivalents	$ 1
Trade and other receivables[1]	21
Inventories	15
Property, plant and equipment	3,003
Right-of-use asset	30
Other assets	12
Trade and other payables	(19)
Derivative financial instrument liabilities	(7)
Lease liabilities	(30)
Provisions	(52)
Fair value of net assets acquired	$ 2,974

[1] The fair value of trade and other receivables approximates the carrying value.

The preliminary purchase price allocation reflects management's best estimate of the fair value of assets acquired and liabilities assumed based on the information obtained and analysis performed to date. Management continues to obtain specific information to support the valuation of working capital, property, plant and equipment, intangible assets and provisions. If new information obtained within one year after the acquisition date about facts and circumstances that existed at the acquisition date identifies adjustments to the above amounts, or any additional provisions that existed at the date of acquisition, then the accounting for the acquisition will be revised.

The Company assumed a provision to return a portion of amounts previously received by Hummel Station, LLC, from the Federal Energy Regulatory Commission (FERC) for reactive supply and voltage control from generation sources service overpayments in the estimated amount of $34 million, included in provisions. The payment will be due eighteen months after final acceptance from FERC is received. Provisions also include decommissioning provisions of $18 million.

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

3. Business combination, continued

Acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC, continued

Revenues and net income from the date of acquisition to June 30, 2025, were $56 million and $25 million, respectively. If the acquisition had occurred on January 1, 2025, consolidated revenues and consolidated net income would have been $1,912 million and $149 million, respectively.

For the six months ended June 30, 2025, the Company incurred acquisition costs of $39 million which were recorded on the Company's consolidated statements of income primarily as other administrative expense.

4. Net finance expense

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	2025	2024
Interest expense				
Interest on loans and borrowings	$ 78	$ 65	$ 146	$ 128
Capitalized interest	(12)	(14)	(21)	(30)
Total interest expense	66	51	125	98
Other finance expense (income)				
Accretion on decommissioning provisions	2	3	5	5
Interest on lease liabilities	2	2	6	6
Interest on government grants receivable	(2)	(3)	(4)	(5)
Other	(4)	-	(7)	(9)
Net finance expense	$ 64	$ 53	$ 125	$ 95

5. Income tax

Income tax expense differs from the amount that would be computed by applying the federal and provincial income tax rates as a result of the following:

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	2025	2024
Net income before tax	$ (185)	$ 99	$ 13	$ 381
Income tax at the statutory rate of 23%	(43)	23	3	88
Increase (decrease) resulting from:				
Non-deductible expenses and non-taxable income	(4)	3	(4)	7
Amounts attributable to non-controlling interests, equity-accounted investments, and tax-equity interests	(7)	(3)	(7)	(5)
Change in unrecognized tax benefits	-	(5)	-	(5)
Statutory and other rate differences	(6)	4	(3)	6
Other	6	1	5	9
Income tax (recovery) expense	$ (54)	$ 23	$ (6)	$ 100

During the second quarter of 2025, there was a reclass of $36 million from other assets to income taxes recoverable resulting from the filing of a portion of the expected Clean Technology investment tax credit claim with the Canada Revenue Agency for the 2024 taxation year.

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

6. (Loss) earnings per share

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

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	2025	2024
(Loss) income for the period attributable to shareholders	$ (132)	$ 75	$ 19	$ 280
Preferred share dividends[1]	(7)	(9)	(14)	(19)
(Loss) earnings available to common shareholders	$ (139)	$ 66	$ 5	$ 261
Weighted average number of common shares	151,219,128	129,545,034	145,232,868	126,607,376
Basic (loss) earnings per share	$ (0.92)	$ 0.51	$ 0.03	$ 2.06
Weighted average number of common shares	151,219,128	129,545,034	145,232,868	126,607,376
Effect of dilutive share purchase options	-	212,207	322,140	224,084
Diluted weighted average number of common shares	151,219,128	129,757,241	145,555,008	126,831,460
Diluted (loss) earnings per share	$ (0.92)	$ 0.51	$ 0.03	$ 2.06

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

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

7. Derivative financial instruments and hedge accounting

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

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.

The Company has elected to apply hedge accounting to certain derivatives used 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.

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

	June 30, 2025					
	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	$ 21	$ 234	$ 1	$ -	$ -	$ 256
Non-current	8	371	6	-	-	385
Derivative instruments liabilities:						
Current	(3)	(254)	(8)	-	-	(265)
Non-current	(2)	(534)	(11)	(1)	-	(548)
Net fair value	$ 24	$ (183)	$ (12)	$ (1)	$ -	$ (172)
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(3)	(70)				
Gigajoules of natural gas purchased[1]		466				
Gigajoules of natural gas basis swaps		63				
Metric tonnes of emission allowances		8				
Number of renewable energy credits		(12)				
Interest rate swaps			$ 1,055	$ 151		
Forward currency buys (U.S. dollars)					$ 13	
Range of remaining contract terms in years	0.1 to 3.5	0.1 to 21.5	0.2 to 1.6	0.2 to 0.5	0.1 to 0.5	

[1] Added 179 Gigajoules as part of the acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC (note 3).

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

7. Derivative financial instruments and hedge accounting, continued

	December 31, 2024					
	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	$ 28	$ 208	$ 2	$ -	$ 6	$ 244
Non-current	17	393	2	-	-	412
Derivative instruments liabilities:						
Current	(2)	(138)	(7)	-	-	(147)
Non-current	(2)	(483)	(9)	-	-	(494)
Net fair value	$ 41	$ (20)	$ (12)	$ -	$ 6	$ 15
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(3)	(49)				
Gigajoules of natural gas purchased		197				
Gigajoules of natural gas basis swaps		63				
Metric tonnes of emission allowances		10				
Number of renewable energy credits		(11)				
Interest rate swaps			$ 800	$ 94		
Forward currency buys (U.S. dollars)					$ 84	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 22.0	0.1 to 2.1	0.2 to 1.0	0.1 to 0.6	

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

	Three months ended June 30, 2025		Three months ended June 30, 2024	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (34)	$ 8	$ 12	$ 10
Energy and emission allowances non-hedges	(241)	55	19	41
Interest rate cash flow hedges	19	3	(2)	4
Interest rate non-hedges	1	-	-	-
Foreign exchange cash flow hedges	(1)	-	1	-
Foreign exchange non-hedges	-	(6)	-	(1)

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

7. Derivative financial instruments and hedge accounting, continued

	Six months ended June 30, 2025		Six months ended June 30, 2024	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains	Realized gains (losses)
Energy cash flow hedges	$ (18)	$ 17	$ 54	$ 3
Energy and emission allowances non-hedges	(172)	115	219	20
Interest rate cash flow hedges	10	6	14	7
Foreign exchange cash flow hedges	(6)	-	30	-
Foreign exchange non-hedges	-	(11)	-	(2)

The following realized and unrealized gains and losses on derivative financial instruments are included in the Company's statements of income:

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	2025	2024
Revenues	$ (224)	$ 169	$ (11)	$ 359
Energy purchases and fuel	46	(99)	(29)	(117)
Foreign exchange loss	(6)	(1)	(11)	(2)
Net finance expense	4	4	6	7

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:

	June 30, 2025
Within one year	$ 39
Between one and five years	52
After five years	20
	$ 111

8. Loans and borrowings

Private offering of senior notes

On May 28, 2025, the Company closed a private offering of $1.7 billion (US$1.2 billion) aggregate principal amount of senior notes (the offering), guaranteed by the Company and certain of the Company's subsidiaries. The offering consisted of $966 million (US$700 million) aggregate principal amount of 5.257% senior notes due 2028 and $690 million (US$500 million) aggregate principal amount of 6.189% senior notes due 2035.

Committed credit facilities

On June 6, 2025, the Company amended the terms of its syndicated credit facility and terminated its $300 million unsecured club credit facility. The amendments to the syndicated credit facility included an increase to the maximum principal amount from $700 million to $1.5 billion, an extension of one year to June 2030, and a change to the modified consolidated net tangible assets to consolidated net tangible assets ratio covenant (not less than 0.75 to 1.0) to be based on total assets. No amounts were drawn on the facilities at the time of the amendment.

On April 14, 2025, the Company entered into a commitment letter with TD Securities Inc. for fully underwritten $2 billion senior unsecured term loans. As the Company amended the terms of its syndicated credit facility, the commitment letter was no longer required and has been terminated.

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

9. Share capital

Issued and fully paid shares

On April 22, 2025, the Company completed a bought deal offering of 11,902,500 common shares and 3,455,000 common shares on a private placement basis, at an offering price of $43.45 per common share for total gross proceeds of approximately $667 million.

Common and preferred share dividends

	Dividends declared							
	For the three months ended June 30,				For the six months ended June 30,			
	2025		2024		2025		2024	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.6519	$101	$ 0.6150	$ 80	$ 1.3038	$ 192	$ 1.2300	$159
Preference:								
Series 1	0.1638	1	0.1638	1	0.3276	2	0.3276	2
Series 3	0.4288	2	0.4288	3	0.8575	5	0.8576	6
Series 5	0.4144	3	0.4144	3	0.8288	6	0.8288	6
Series 11[1]	N/A	-	0.3594	2	N/A	-	0.7188	4

[1] On June 30, 2024, the Company redeemed all of its issued and outstanding 5.75% cumulative rate reset preference shares, Series 11. The final quarterly dividend was paid on the redemption date.

	Dividends paid[2]							
	For the three months ended June 30,				For the six months ended June 30,			
	2025		2024		2025		2024	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[3]	$ 0.6519	$ 91	$ 0.6150	$ 79	$ 1.3038	$ 182	$ 1.2300	$151

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

[3] For the six months ended June 30, 2025 common dividends consist of $148 million paid in cash and $34 million through the Company’s dividend re-investment plan (six months ended June 30, 2024, $119 million paid in cash and $33 million through the Company’s dividend re-investment plan).

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

10. Financial Instruments

Fair values

The Company classifies and measures its cash and cash equivalents, trade and other receivables, and trade and other payables at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		June 30, 2025		December 31, 2024	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets[1]					
Government grant receivable[2]	Level 2	$ 434	$ 403	$ 438	$ 400
Financial liabilities[1]					
Loans and borrowings	Level 2	$ 6,941	$ 7,197	$ 4,976	$ 5,244

[1] Includes current portion.

[2] Government grant receivable includes $277 million related to off-coal compensation from the Government of Alberta (GoA). As described in the Company's 2024 annual consolidated financial statements, the GoA previously withheld approximately $2.7 million from each of the payments from 2017 to 2024, which the Company disputed. The annual payment amounts recorded by the Company were previously reduced by $1.5 million for 2017 to 2024. During the second quarter of 2025, the Company settled the disputed amounts with the GoA and received a cash payment of $10 million, which resulted in a decrease to the amount previously recorded of approximately $5 million, recorded through (loss) gain on disposals and other transactions.

Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be sold or transferred between market participants in an orderly transaction at the measurement date. Fair value measurements recognized in the consolidated statements of financial position are categorized into levels within the fair value hierarchy based on the nature of the valuation inputs, and precedence is given to observable inputs over unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The valuation techniques used by the Company in determining the fair value of its financial instruments are the same as those used at December 31, 2024.

Fair value measurements are categorized into levels based upon the lowest level of significant input, as described in the Company's 2024 annual consolidated financial statements. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment.

The Company recognizes transfers between levels of the fair value hierarchy at the end of the reporting period during which the change has occurred. There were no transfers between Level 1 and Level 2.

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 2024 annual consolidated financial statements.

	June 30, 2025			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 524	$ 117	$ 641
Derivative financial instruments liabilities	-	(537)	(276)	(813)

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

10. Financial instruments, continued

Fair value hierarchy, continued

	December 31, 2024			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 520	$ 136	$ 656
Derivative financial instruments liabilities	-	(349)	(292)	(641)

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2024 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.

Valuation techniques used in Level 3 fair value measurements

The Company has various commodity, renewable energy agreements, and renewable energy credit (REC) contracts with terms that extend beyond a liquid trading period. Certain of these contracts include notional quantities based on future actual generation of underlying generation facilities. As forward market prices and actual generation 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 as Level 3 fair value measurements. The fair values of the Company's commodity derivatives classified as Level 3 are determined by applying mark-to-forecast models. The valuation models used to calculate the fair values of the derivative financial instrument assets and liabilities within Level 3 are prepared by internal subject matter experts and are reviewed by the Company's commodity risk group and management. The valuation techniques and the associated inputs are assessed on a regular basis for ongoing reasonability.

The table below presents ranges for the Company's Level 3 inputs:

	June 30, 2025	December 31, 2024
REC pricing (per certificate) – Solar	$3 to $251	$3 to $201
REC pricing (per certificate) – Wind	$3 to $5	$3 to $8
Forward power pricing (per MWh) – Solar	$21 to $165	$15 to $113
Forward power pricing (per MWh) – Wind	$16 to $146	$15 to $142
Average monthly notional generation (MWh) – Solar	6,540 to 13,000	6,554 to 13,044
Average monthly notional generation (MWh) – Wind	16,077 to 60,146	16,540 to 60,060

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

	June 30, 2025	December 31, 2024
REC pricing – Solar	$ 1	$ 2
REC pricing – Wind	2	4
Forward power pricing – Solar	15	4
Forward power pricing – Wind	48	59
Generation – Solar	2	4
Generation – Wind	15	13

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

10. Financial instruments, continued

Fair value hierarchy, continued

Continuity of Level 3 balances

The Company classifies financial instruments in Level 3 of the fair value hierarchy when there is at least one significant unobservable input used in the valuation model. 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:

	June 30, 2025	December 31, 2024
At January 1[1]	$ (156)	$ (297)
Additions	(12)	27
Unrealized and realized (losses) gains included in net income[2]	(22)	137
Settlements	21	(15)
Transfers[3]	-	1
Foreign exchange gains (losses)	10	(9)
At end of period	$ (159)	$ (156)

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

[2] Recorded in revenues.

[3] Relates to transfers from Level 3 to Level 2 when pricing inputs become readily observable. There were no transfers from Level 2 to Level 3.

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 other levels.

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

11. Segment information

The Company reassessed its reportable segments due to changes in internal reporting for performance results provided to the Company's Chief Operating Decision Maker (CODM). Comparative segment information has been restated to conform to the current period’s presentation.

The Company identifies its reportable segments both by business activity and by geographical areas and has four reportable segments described below:

- Flexible generation – Flexible generation refers to the ability of power-generating facilities to quickly adjust output based on grid demand. These dispatchable power sources include natural gas facilities and energy storage. Reportable segments associated with this activity include Canada flexible generation, and U.S. flexible generation. The Company actively trades in North American power, natural gas and environmental markets. The majority of the Company’s trading activities relate directly to assets or portfolios of assets within the flexible generation segments and accordingly are reported within these segments. Specifically, trading related to Alberta flexible generation portfolio of assets is included within Canada flexible generation, and trading to optimize U.S. facilities as well as other U.S. trading is included within U.S. flexible generation.
- Renewables – Renewable generation includes the Company's wind and solar facilities. Reportable segments associated with this activity include Canada renewables and U.S. renewables.

Corporate includes costs of support services such as treasury, finance, internal audit, legal, people services, enterprise risk management, asset management, and environment, health and safety.

The following tables provide each reportable segment's results in the format that the Company's CODM reviews in making operating decisions and assessing performance. The CODM assesses the performance of the operating segments based on adjusted EBITDA, which reflects earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation from our joint venture interests, gains or losses on disposals, unrealized changes in fair value of commodity derivatives and emission credits, and other items that are not reflective of the long-term performance of the Company's underlying business. The tables below show the reconciliation of the total segment adjusted EBITDA to income before tax, as reported under IFRS.

	Three months ended June 30, 2025								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 340	$ 42	$ 119	$ 44	$ 17	$ 562	$ (121)		$ 441
Energy purchases and fuel	(277)	(1)	(39)	6	-	(311)	51		(260)
Other raw materials and operating charges	(21)	(6)	(25)	(5)	(3)	(60)	7		(53)
Staff costs and employee benefits expense	(12)	(2)	(9)	-	(34)	(57)	4		(53)
Other administrative expense	(15)	(4)	(15)	(6)	(56)	(96)	7		(89)
Remove unrealized changes in fair value of commodity derivatives	151	(2)	110	(12)	-	247	-	(247)	-
Remove other non-recurring items	-	-	-	-	37	37	-	(37)	-
Adjusted EBITDA[2]	166	27	141	27	(39)	322			
Depreciation and amortization									(138)
Foreign exchange gain									21
Losses on disposals and other transactions									(6)
Net finance expense									(64)
Income from equity-accounted investments									16
Loss before tax									$ (185)

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

11. Segment information, continued

	Three months ended June 30, 2024								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 526	$ 49	$ 255	$ 54	$ -	$ 884	$ (110)		$ 774
Energy purchases and fuel	(305)	(2)	(86)	(2)	-	(395)	35		(360)
Other raw materials and operating charges	(24)	(7)	(24)	(5)	(1)	(61)	10		(51)
Staff costs and employee benefits expense	(15)	-	(6)	(1)	(30)	(52)	2		(50)
Other administrative expense	(15)	(5)	(16)	(6)	(7)	(49)	6		(43)
Remove unrealized changes in fair value of commodity derivatives	(8)	6	5	(11)	-	(8)	-	8	-
Remove other non-recurring items	4	-	-	-	-	4	-	(4)	-
Adjusted EBITDA[2]	163	41	128	29	(38)	323			
Depreciation and amortization									(120)
Foreign exchange loss									(4)
Loss on disposals and other transactions									(17)
Net finance expense									(53)
Income from equity-accounted investments									23
Income before tax									$ 99

	Six months ended June 30, 2025								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 979	$ 58	$ 516	$ 115	$ 31	$ 1,699	$ (270)		$ 1,429
Energy purchases and fuel	(584)	(3)	(284)	6	-	(865)	116		(749)
Other raw materials and operating charges	(41)	(12)	(57)	(9)	(4)	(123)	17		(106)
Staff costs and employee benefits expense	(27)	(2)	(19)	(1)	(53)	(102)	8		(94)
Other administrative expense	(29)	(8)	(29)	(11)	(73)	(150)	16		(134)
Remove unrealized changes in fair value of commodity derivatives	71	27	133	(42)	-	189	-	(189)	-
Remove other non-recurring items	4	-	-	-	37	41	-	(41)	-
Adjusted EBITDA[2]	373	60	260	58	(62)	689			
Depreciation and amortization									(264)
Foreign exchange gain									23
Losses on disposals and other transactions									(7)
Net finance expense									(125)
Income from equity-accounted investments									40
Income before tax									$ 13

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

11. Segment information, continued

	Six months ended June 30, 2024								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 1,321	$ 234	$ 491	$ 53	$ 3	$ 2,102	$ (209)		$ 1,893
Energy purchases and fuel	(755)	(10)	(198)	(1)	-	(964)	78		(886)
Other raw materials and operating charges	(45)	(14)	(43)	(9)	(1)	(112)	15		(97)
Staff costs and employee benefits expense	(29)	(1)	(14)	(1)	(59)	(104)	5		(99)
Other administrative expense	(30)	(10)	(26)	(13)	(37)	(116)	17		(99)
Remove unrealized changes in fair value of commodity derivatives	(124)	(114)	2	28	-	(208)	-	208	-
Remove other non-recurring items	4	-	-	-	10	14	-	(14)	-
Adjusted EBITDA[2]	342	85	212	57	(84)	612			
Depreciation and amortization									(242)
Foreign exchange loss									(14)
Loss on disposals and other transactions									(15)
Net finance expense									(95)
Income from equity-accounted investments									35
Income before tax									$ 381

[1] For internal reporting purposes, adjusted EBITDA from the Company's equity-accounted investments has been presented on a proportionate basis that reflects the Company's share of each investee's earnings on a line-by-line basis. These amounts are reported within Canada flexible generation for York Energy, Canada renewables for Quality Wind and Port Dover Nanticoke Wind (from the time of the sell-down on December 20, 2024 onwards), and U.S. flexible generation for MCV Partners LLC and Harquahala. Proportionate financial information is not, and is not intended to be, presented in accordance with IFRS. Under IFRS, these investments have been accounted for as joint ventures using the equity method.

[2] Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Additional geographic information

The Company’s Canadian facilities are located in Alberta, British Columbia and Ontario and its U.S. facilities in Alabama, Arizona, California, Illinois, Kansas, Michigan, New Mexico, North Carolina, North Dakota, Ohio, Pennsylvania, Texas and Washington. The Company also holds a portfolio of wind and solar development sites in Canada and the U.S.

Select non-current assets within each geographic area are:

	At June 30, 2025			At December 31, 2024		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 5,511	$ 5,450	$ 10,961	$ 5,457	$ 2,604	$ 8,061
Equity-accounted investments	396	655	1,051	397	699	1,096
Intangible assets and goodwill	447	203	650	519	225	744
Right-of-use assets	51	88	139	54	64	118
Other assets[3]	66	51	117	73	84	157
	$ 6,471	$ 6,447	$ 12,918	$ 6,500	$ 3,676	$ 10,176

[3] Includes current portion of finance lease receivable.

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

11. Segment information, continued

Major customer

For the three and six months ended June 30, 2025, the Company recorded revenues of $132 million and $281 million, respectively, from the Alberta Electric System Operator, within the Canada flexible generation and Canada renewables segments (three and six months ended June 30, 2024 - $105 million and $461 million, respectively). There were no other entities that accounted for more than 10 percent of the Company's total revenues.

Disaggregation of revenues from contracts with customers

The Company's revenues from contracts with customers are disaggregated by major type of revenues and operating segments:

	Three months ended June 30, 2025						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 382	$ 20	$ 146	$ 16	$ 564	$ (187)	$ 377
Emission credit revenues	-	11	-	-	11	19	30
Total revenues[4]	$ 382	$ 31	$ 146	$ 16	$ 575	$ (168)	$ 407

	Three months ended June 30, 2024						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 357	$ 35	$ 86	$ 13	$ 491	$ 236	$ 727
Emission credit revenues	-	12	-	-	12	14	26
Total revenues[4]	$ 357	$ 47	$ 86	$ 13	$ 503	$ 250	$ 753

	Six months ended June 30, 2025						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 839	$ 39	$ 301	$ 35	$ 1,214	$ 115	$ 1,329
Emission credit revenues	-	25	-	2	27	6	33
Total revenues[4]	$ 839	$ 64	$ 301	$ 37	$ 1,241	$ 121	$ 1,362

	Six months ended June 30, 2024						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,000	$ 86	$ 183	$ 27	$ 1,296	$ 504	$ 1,800
Emission credit revenues	-	22	-	2	24	26	50
Total revenues[4]	$ 1,000	$ 108	$ 183	$ 29	$ 1,320	$ 530	$ 1,850

[4] Included within trade and other receivables at June 30, 2025, were amounts related to contracts with customers of $294 million (2024 - $267 million).

12. Comparative figures

The comparative figures have been reclassified to conform with the presentation adopted for 2025.