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Capital Power reports third quarter 2026 results

EDMONTON, Alberta – November 2, 2026 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended September 30, 2026.

Highlights

- Long-term Energy Supply Agreement (ESA) for 250 megawatts of capacity and energy with Meta Platforms, Inc. in support of a data centre
- Subsequent to the quarter, the 100MW expansion at East Windsor received approval to operate in the Ontario market
- Generated net cash flows from operating activities of $381 million and adjusted funds from operations (AFFO)[1] of $306 million
- Generated net income of $67 million and adjusted EBITDA[1] of $553 million
- Increased annual common share dividend by 2%, representing the 13th consecutive year of increase

CEO Message

Our third-quarter results reflect the continued execution of our strategy and the value of our diversified portfolio, with strong contributions from our Alberta, PJM and Ontario assets. Our portfolio pairs stable contracted cash flows with exposure to markets where growing electricity demand and tightening supply are creating meaningful upside.

Approximately 75% of our expected 2026 adjusted EBITDA is underpinned by long-term contracts. Indicative of our strategy of working with high-quality counterparties, 100% of our power purchase agreements are held with investment grade counterparties and over 70% are utilities or system operators. Our Energy Supply Agreement with Meta is the latest example of these efforts to secure longer-term cash flows across our core markets. Over the past 18 months, we have delivered on ~2 GW of contracted capacity with a weighted average contract life of approximately 15 years.

With a strong balance sheet and disciplined capital allocation, we are also evaluating opportunities to extract additional value from our existing sites through uprates, expansions and co-located battery storage. These opportunities support our focus on growth and shareholder returns. The 2% annual dividend increase announced in the second quarter marks the 13th consecutive year of increase.

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

Revised 2026 Annual Guidance

Priority	2026 targets	Status at September 30, 2026
Generate financial stability and strength	AFFO [3] of **$890 million to $1,010 million** Adjusted EBITDA [3] of **$1,565 million to $1,765 million**	**$788 million** [1] **$1,308 million** [1]
Execution of major turnarounds	Sustaining capital expenditures [4] Revised target: **$350 million to $370 million** Original target: **$290 million to $330 million**	**$270 million** [1,2]
Portfolio optimization	Re-contract/contract natural gas generation Maximize facility asset life and value	In July, the Company entered into a long-term ESA with Meta for 250 MW of capacity and energy in support of a data centre in Alberta (see Significant Events). In Q1 2026, the Company extended its summer tolling agreement for Arlington Valley from 2031 to October 2038. As part of this agreement, the facility will undergo a 35 MW capacity uprate (see Significant Events). Discussions with counterparties to supply energy solutions from across our fleet are in progress.
Expand flexible generation portfolio	Continue construction on Ontario growth and commercial initiative projects Continue to explore opportunities to build or acquire natural gas generation facilities	Construction is underway and the projects are progressing to meet their targeted completion dates (see Capital Expenditures and Investments). Subsequent to the quarter, the 100MW expansion at East Windsor received approval to operate in the Ontario market.
Grow renewables portfolio	Continue construction of North Carolina growth projects Continue to explore opportunities to build or acquire renewables facilities	Construction for the North Carolina solar projects continued into 2026 (see Capital Expenditures and Investments). Commissioning activities for Hornet and Bear Branch Solar are progressing towards a Q4 2026 completion.
Advance balanced energy solutions such as low-carbon solutions	Evaluate SMRs in Alberta Continue to explore opportunities to co-locate with data centres across North America	Pre-feasibility study work for the Alberta SMR project with Ontario Power Generation remains on track, and we continue to evaluate the development opportunity through this project. We remain in various stages of discussion with several prospective customers about the potential to co-locate or otherwise serve data centre demand at our sites across North America.

[1] For the nine months ended September 30, 2026.

[2] Net of partner contributions of $10 million and including our share of equity-accounted investments sustaining capital expenditures of $38 million.

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

[4] The Company revised its guidance range for 2026 sustaining capital expenditures reflecting unplanned outage work, primarily for the U.S. flexible generation fleet, and the advancement of a planned outage from 2027 into the fourth quarter of 2026 to ensure high reliability through 2027. The increase is event-driven, and a significant portion relates to insurable events. Insurance recoveries anticipated in 2026 and 2027, together with concessions from original equipment manufacturers (OEMs), are expected to meaningfully offset the cash impact.

Operational and Financial Highlights[1]

($ millions, except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2026	**2025**	**2026**	**2025**
Electricity generation (Gigawatt hours)[2]	14,485	13,374	36,090	31,951
Generation facility availability (%)[3]	93	93	91	92
Revenues and other income	831	1,213	2,776	2,642
Net income	67	153	39	172
Net income attributable to shareholders of the Company	67	154	38	173
Basic earnings per share ($)	0.37	0.94	0.09	1.02
Diluted earnings per share ($)[4]	0.37	0.94	0.09	1.01
Adjusted EBITDA[5]	553	477	1,308	1,166
AFFO[5]	306	369	788	822
AFFO per share ($)[5]	1.94	2.37	5.03	5.53
Net cash flows from operating activities	381	404	907	757
Purchase of property, plant and equipment and other assets, net	167	147	642	576
Dividends per common share, declared ($)	0.7048	0.6910	2.0868	1.9948

[1] The operational and financial highlights in this press release should be read in conjunction with the Management's Discussion and Analysis (MD&A) and the unaudited condensed interim financial statements for the nine months ended September 30, 2026.

[2] Gigawatt hours (GWh) of electricity generation reflects the Company's share of facility output and includes GWh discharged from BESS.

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

[5] 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.

Revenues and other income decreased quarter-over-quarter due to unfavourable changes in unrealized fair value on commodity derivatives and emission credits, primarily in the U.S. flexible generation segment. Excluding these non-cash fair value changes, revenues and other income increased, driven by higher contributions from the U.S. flexible generation segment, where stronger PJM pricing and summer demand at Hummel Station and Rolling Hills and higher contracted revenues at Arlington Valley more than offset less favourable hedge settlements at La Paloma.

Adjusted EBITDA increased quarter-over-quarter primarily due to:

- higher contributions from the Hummel Station and Rolling Hills facilities acquired in June 2025, reflecting stronger PJM power prices and summer demand in the third quarter and a full nine months of operations in 2026,
- higher results in the Canada flexible generation segment, as favourable portfolio optimization, higher generation and pricing at Goreway, and contributions from the Ontario BESS projects that commenced operations in September 2025 more than offset the impact of lower Alberta spot power prices and lower generation,
- partially offset by a lower contribution from La Paloma, where the financial hedges entered into following its acquisition settled less favourably than in 2025.

AFFO was $306 million and $788 million for the three and nine months ended September 30, 2026, respectively, compared with $369 million and $822 million in the corresponding periods in 2025. Despite higher adjusted EBITDA, as described above, AFFO for both the quarter and year-to-date periods was impacted by the following:

- higher sustaining capital expenditures, primarily reflecting the heavy maintenance schedule for the Alberta fleet, rotor replacements at Rolling Hills and Harquahala, and a full year of planned maintenance at Hummel Station and Rolling Hills,
- higher net finance expense,
- current income tax expense of $35 million and $65 million for the three and nine months ended September 30, 2026, respectively, compared with income tax recoveries of $16 million and $72 million in the corresponding periods of 2025, reflecting higher taxable income due to lower tax depreciation, and
- the non-cash straight-line recognition of capacity payments under the Arlington Valley summer tolling agreement, which contributed favourably to adjusted EBITDA, and which did not affect AFFO,
- the year-to-date impacts were partially offset by the recognition of $174 million in Clean Technology ITCs for eligible Canadian renewables projects in the second quarter of 2026.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on November 2, 2026 at 9:00 a.m. ABT (8:00 a.m. MT / 10:00 a.m. ET) to discuss the third quarter financial results. The webcast can be accessed at: https://edge.media-server.com/mmc/p/z44y8ypg/. 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 equity-accounted investments, acquisition and integration costs, and other items that are not reflective of the Company's facility operating performance (adjusted EBITDA), and (ii) adjusted funds from operations (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

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 September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Net income	**67**	**153**	**39**	**172**
Depreciation and amortization	207	157	555	421
Unrealized changes in fair value of commodity derivatives and emission credits	89	(13)	238	176
Foreign exchange (gain) loss	(2)	7	20	(16)
Net finance expense	95	92	282	217
Acquisition and integration costs	–	4	–	41
Loss on disposals and other transactions	17	5	17	12
Other items[1]	45	37	142	110
Other non-recurring items[2]	(2)	–	–	4
Income tax expense	37	35	15	29
Adjusted EBITDA	**553**	**477**	**1,308**	**1,166**

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

[2] For the three and nine months ended September 30, 2026, other non-recurring items reflect a partial reimbursement for a provision assumed in the acquisition of Hummel Station, LLC, related to overpayments to FERC and legal fees related to a dispute with a contractor regarding construction work on the Genesee Repowering project. The nine months ended September 30, 2025 reflects costs related to the end-of-life of Genesee coal operations.

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.

The Company's AFFO definition includes government grants related to off-coal compensation to be received annually to 2030. During the second quarter of 2026, the Company updated the composition of AFFO and AFFO per share to reflect the introduction of similar government grants where cash grants form part of the operating returns on qualifying capital investment and support the Company's cash generation and liquidity profile. As a result, AFFO and AFFO per share now include Clean Technology ITCs associated with eligible Canadian renewables projects.

The Company has included $174 million in government grants related to Clean Technology ITCs, representing approximately 30% of eligible Canadian renewables project costs. These amounts are included in AFFO and AFFO per share in the period in which the required filing with the applicable tax authority is completed, rather than when cash is received to eliminate timing variability associated with administrative processing. While Capital Power expects amounts ultimately received to be consistent with amounts filed, actual receipts may differ. The amendment did not impact previously reported AFFO or AFFO per share amounts.

AFFO represents net cash flows from operating activities adjusted to:

- exclude timing impacts of cash receipts and payments that may impact period-to-period comparability by including deductions for net finance expense and current income tax expense, and excluding deductions for interest paid, deductions for income taxes paid and changes in operating working capital,
- include our share of AFFO of equity-accounted investments and exclude distributions received from our equity-accounted investments which are calculated after the effect of non-operating activity equity-accounted investments debt payments,
- include government grants which represent a portion of operating returns on capital investment recognized in the period that they are either contractually obligated to be received by Capital Power or the period in which Capital Power has completed the necessary filing with the applicable tax authority to eliminate timing uncertainty due to administrative filing processes,
- exclude 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 except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2026	**2025**	**2026**	**2025**
Net cash flows from operating activities	**381**	**404**	**907**	**757**
Add (deduct):				
Interest paid	95	87	254	202
Change in fair value of derivatives reflected as cash settlement	4	—	10	7
Realized gain on settlement of interest rate derivatives	(12)	—	(12)	(17)
Distributions received from equity-accounted investments	(7)	(9)	(72)	(47)
Miscellaneous financing charges[1]	4	4	11	(2)
Income taxes recovered	(12)	(11)	(12)	(14)
Change in non-cash operating working capital	(26)	(77)	(39)	(23)
	46	(6)	140	106
Net finance expense [2]	(87)	(81)	(258)	(192)
Current income tax (expense) recovery [3]	(35)	16	(65)	72
Sustaining capital expenditures [4]	(87)	(44)	(232)	(85)
Preferred share dividends paid	(7)	(7)	(22)	(20)
Government grants [5]	50	50	224	60
Remove tax equity interests' respective shares of AFFO	1	(1)	—	(4)
AFFO from equity-accounted investments	43	38	98	101
Acquisition and integration costs [6]	—	3	(1)	41
Other non-recurring items [7]	1	(3)	(3)	(14)
AFFO	**306**	**369**	**788**	**822**
Weighted average number of common shares outstanding (millions)	157.4	155.3	156.8	148.6
AFFO per share ($)	**1.94**	**2.37**	**5.03**	**5.53**

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

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

[3] For the three and nine months ended September 30, 2025, excludes current income tax expense related to the partial divestiture of Quality Wind and Port Dover and Nanticoke Wind in 2024 as the amount is classified as an investing activity.

[4] Sustaining capital expenditures net of partner contributions of $1 million and $10 million for the three and nine months ended September 30, 2026, respectively, compared with $2 million and $8 million for the three and nine months ended September 30, 2025.

[5] For the nine months ended September 30, 2026, reflects recognition of $174 million in Clean Technology ITCs filed with the applicable tax authority, representing approximately 30% of eligible Canadian renewables project costs. For the three and nine months ended September 30, 2026 and September 30, 2025, reflects payments received from the Government of Alberta for the settlement of previously disputed off-coal compensation payments as described in the Company's 2025 annual consolidated financial statements.

[6] For the nine months ended September 30, 2026, current income tax recoveries of $1 million related to prior period acquisition and integration costs. For the three and nine months ended September 30, 2025, net of current income tax recoveries of $1 million and $2 million.

[7] For the three months ended September 30, 2026, other non-recurring items included $3 million of legal costs related to a contractor dispute concerning construction work at the Genesee Repowering project, offset by a $5 million recovery from the settlement of the FERC reactive supply and voltage control service overpayment provision and current income tax expense of $3 million. For the nine months ended September 30, 2026, other non-recurring items included $5 million of legal costs related to a contractor dispute at the Genesee Repowering project, offset by a $5 million recovery from the settlement of the FERC reactive supply and voltage control service overpayment provision and current income tax recoveries of $3 million associated with non-recurring items recognized in prior periods. For the three months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind virtual power purchase agreement (VPPA) of $5 million, net of current income tax recoveries of $8 million related to other non-recurring items recognized in the current and prior periods. For the nine months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind VPPA and end-of-life of Genesee coal operations of $5 million each, net of current income tax recoveries of $24 million related to other non-recurring items recognized in the current and prior periods.

Forward-looking information

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

Material forward-looking information in this press release includes, among other things, expectations regarding:

- our 2026 adjusted EBITDA and revised sustaining capital expenditures targets, and
- recoverability of insurance proceeds for submitted claims.

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 this forward-looking information relate to:

- electricity and other energy (including natural gas) and carbon prices,
- the Company's performance,
- the Company's business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- the energy needs of certain jurisdictions,
- 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 the 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 include:

- Meta's completion of a data centre as contemplated in the ESA,
- 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 market prices and 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 the MD&A.

See Risks and Risk Management in our 2025 Integrated Annual Report, for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking information, which speak only as of the date made and that other events or circumstances, although not listed above, could cause Capital Power's actual results to differ materially from those estimated or projected and expressed in, or implied by the forward-looking information. Capital Power does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking information 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.

About Capital Power

Capital Power is one of North America's leading independent power producers, with approximately 12 GW of generation capacity across 35 facilities. Our portfolio includes natural gas, renewables, and battery energy storage solutions. We deliver power generation at utility-scale through a flexible and resilient fleet built to meet growing electricity demand. Backed by an investment-grade credit rating, we provide safe, reliable power communities can depend on.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A), prepared as of October 30, 2026, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the nine months ended September 30, 2026, the audited consolidated financial statements and the 2026 Performance Targets, the Executing our Strategic Focus - Deliberate Growth, Durable Performance, the Business Report, and the Forward-Looking Information sections of the Integrated Annual Report of Capital Power Corporation for the year ended December 31, 2025 (the 2025 Integrated Annual Report), the Annual Information Form of Capital Power Corporation dated March 4, 2026, and the cautionary statements regarding Forward-Looking Information which begin on page 10.

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

In this MD&A, financial information for the nine months ended September 30, 2026 and September 30, 2025 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) Accounting Standards as issued by the International Accounting Standards Board and constitute Canadian generally accepted accounting principles (GAAP). All financial information is presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of October 30, 2026.

FORWARD-LOOKING INFORMATION

Forward-looking information or statements (collectively, "forward-looking information") included in this MD&A are provided to inform our shareholders, potential investors and other stakeholders about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this 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, among other things, expectations regarding:

- our priorities and long-term strategies, including our strategy of acquiring and optimizing existing natural gas capacity, our corporate and decarbonization strategies, and our pursuit of lower-carbon power solutions,
- our 2026 performance targets, including sustaining capital expenditures, adjusted funds from operations (AFFO) and adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA), and the expected trajectory of performance relative to guidance, re-contracting/contracting natural gas generation, maximizing facility asset life and value, continuing construction of growth and commercial initiative projects, and continuing to explore opportunities to build or acquire natural gas generation and renewables facilities, including opportunities to co-locate with data centres,
- 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 projected long-term targeted dividend growth,
- our sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, various aspects around existing, planned and potential development projects, acquisitions (including East Windsor Expansion, Maple Leaf Solar, Hornet Solar, and Bear Branch Solar projects), including expectations around timing and substantial completion, generation capacity, costs of technologies selected, environmental and sustainability benefits, and commercial and partnership arrangements,
- our 2026 estimated capital expenditures for previously announced growth projects,
- the performance of future projects and the performance of such projects in comparison to the market,
- recoverability of insurance proceeds for submitted claims,
- anticipated pricing trends, growth opportunities, market conditions, and future power demand in the Pennsylvania-New Jersey-Maryland (PJM) market including the intention to extend the capacity market price collar through 2030, pending Federal Energy Regulatory Commission (FERC) approval,
- power requirements and demand, future growth, and emerging opportunities in our target markets,
- our plans for continuing to evaluate the deployment of nuclear through small modular reactors (SMRs) in Alberta,
- market and regulation designs and regulatory and legislative proposals and changes, regulatory updates, initiatives, projects and the impact thereof on the Company's core markets and business,
- 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,
- the construction by Meta Platforms, Inc. (Meta) of the data centre and the timing of Meta's project's load entering service,
- the outcomes resulting from the Arlington Valley tolling agreement extension and capacity uprate project, including expectations regarding the anticipated capacity payment increase from the facility and the anticipated timing and realization of such financial benefits, and
- the anticipated benefits, outcomes, projected timing, and terms of strategic agreements.

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 this forward-looking information relate to:

- electricity and other energy (including natural gas) and carbon prices,
- the Company's performance,
- the Company's business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- the energy needs of certain jurisdictions,
- 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 include:

- Meta's completion of a data centre as contemplated in the energy supply agreement (ESA),
- 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 market prices and 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 2025 Integrated Annual Report, for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking information, which speaks only as of the date made and that other events or circumstances, although not listed above, could cause Capital Power's actual results to differ materially from those estimated or projected and expressed in, or implied by the forward-looking information. Capital Power does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking information 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 one of North America's leading independent power producers, with approximately 12 GW of generation capacity across 35 facilities. Our portfolio includes natural gas, renewables, and battery energy storage solutions (BESS). We deliver power generation at utility-scale through a flexible and resilient fleet built to meet growing electricity demand. Backed by an investment-grade credit rating, we provide safe, reliable power communities can depend on.

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 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, commercial initiatives for data centres and renewables growth in the U.S. as well as 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.

Capital Power is reaffirming its 2026 guidance for adjusted EBITDA of $1,565 million to $1,765 million and AFFO of $890 million to $1,010 million, supported by strong year-to-date performance across the portfolio. The guidance range for 2026 sustaining capital expenditures has been revised to $350 million to $370 million (previously $290 million to $330 million), reflecting unplanned outage work, primarily for the U.S. flexible generation fleet, and the advancement of a planned outage from 2027 into the fourth quarter of 2026 to ensure high reliability through 2027. The increase is event-driven, and a significant portion relates to insurable events. Insurance recoveries anticipated in 2026 and 2027, together with concessions from original equipment manufacturers (OEMs), are expected to meaningfully offset the cash impact.

The updated 2026 targets and forecasts are based on numerous assumptions, including power and natural gas price forecasts. They do not include the effects of potential future acquisitions or development activities, asset sell-downs or potential market and operational impacts relating to unplanned facility outages, including outages at facilities of other market participants, and the related impacts on market power prices.

Operational priorities and performance targets for Capital Power in 2026 include a balanced approach to the energy transition:

Priority	2026 targets	Status at September 30, 2026
Generate financial stability and strength	AFFO [3] of **$890 million to $1,010 million** Adjusted EBITDA [3] of **$1,565 million to $1,765 million**	**$788 million** [1] **$1,308 million** [1]
Execution of major turnarounds	Sustaining capital expenditures [4] Revised target: **$350 million to $370 million** Original target: **$290 million to $330 million**	**$270 million** [1,2]
Portfolio optimization	Re-contract/contract natural gas generation Maximize facility asset life and value	In July, the Company entered into a long-term ESA with Meta for 250 MW of capacity and energy in support of a data centre in Alberta (see Significant Events). In Q1 2026, the Company extended its summer tolling agreement for Arlington Valley from 2031 to October 2038. As part of this agreement, the facility will undergo a 35 MW capacity uprate (see Significant Events). Discussions with counterparties to supply energy solutions from across our fleet are in progress.
Expand flexible generation portfolio	Continue construction on Ontario growth and commercial initiative projects Continue to explore opportunities to build or acquire natural gas generation facilities	Construction is underway and the projects are progressing to meet their targeted completion dates (see Capital Expenditures and Investments). Subsequent to the quarter, the 100MW expansion at East Windsor received approval to operate in the Ontario market.
Grow renewables portfolio	Continue construction of North Carolina growth projects Continue to explore opportunities to build or acquire renewables facilities	Construction for the North Carolina solar projects continued into 2026 (see Capital Expenditures and Investments). Commissioning activities for Hornet and Bear Branch Solar are progressing towards a Q4 2026 completion.
Advance balanced energy solutions such as low-carbon solutions	Evaluate SMRs in Alberta Continue to explore opportunities to co-locate with data centres across North America	Pre-feasibility study work for the Alberta SMR project with Ontario Power Generation remains on track, and we continue to evaluate the development opportunity through this project. We remain in various stages of discussion with several prospective customers about the potential to co-locate or otherwise serve data centre demand at our sites across North America.

[1] For the nine months ended September 30, 2026.

[2] Net of partner contributions of $10 million and including our share of equity-accounted investments sustaining capital expenditures of $38 million.

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

[4] The Company revised its guidance range for 2026 sustaining capital expenditures reflecting unplanned outage work, primarily for the U.S. flexible generation fleet, and the advancement of a planned outage from 2027 into the fourth quarter of 2026 to ensure high reliability through 2027. The increase is event-driven, and a significant portion relates to insurable events. Insurance recoveries anticipated in 2026 and 2027, together with concessions from OEMs, are expected to meaningfully offset the cash impact.

The Board of Directors has approved a 2% increase in the common share dividend for 2026 with a long-term targeted dividend growth guidance of 2-4% until 2030. Each annual increase is premised on the assumptions listed under Forward-looking information and subject to approval by the Board at the time of 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 equity-accounted investments, 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

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 September 30,		Nine months ended September 30,	
	2026	**2025**	**2026**	**2025**
Net income	**67**	**153**	**39**	**172**
Depreciation and amortization	207	157	555	421
Unrealized changes in fair value of commodity derivatives and emission credits	89	(13)	238	176
Foreign exchange (gain) loss	(2)	7	20	(16)
Net finance expense	95	92	282	217
Acquisition and integration costs	–	4	–	41
Loss on disposals and other transactions	17	5	17	12
Other items [1]	45	37	142	110
Other non-recurring items [2]	(2)	–	–	4
Income tax expense	37	35	15	29
Adjusted EBITDA [3]	**553**	**477**	**1,308**	**1,166**

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

[2] For the three and nine months ended September 30, 2026, other non-recurring items reflect a partial reimbursement for a provision assumed in the acquisition of Hummel Station, LLC, related to overpayments to FERC and legal fees related to a dispute with a contractor regarding construction work on the Genesee Repowering project. The nine months ended September 30, 2025 reflects costs related to the end-of-life of Genesee coal operations.

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

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.

The Company's AFFO definition includes government grants related to off-coal compensation to be received annually to 2030. During the second quarter of 2026, the Company updated the composition of AFFO and AFFO per share to reflect the introduction of similar government grants where cash grants form part of the operating returns on qualifying capital investment and support the Company's cash generation and liquidity profile. As a result, AFFO and AFFO per share now include Clean Technology Investment Tax Credits (ITCs) associated with eligible Canadian renewables projects.

The Company has included $174 million in government grants related to Clean Technology ITCs, representing approximately 30% of eligible Canadian renewables project costs. These amounts are included in AFFO and AFFO per share in the period in which the required filing with the applicable tax authority is completed, rather than when cash is received to eliminate timing variability associated with administrative processing. While Capital Power expects amounts ultimately received to be consistent with amounts filed, actual receipts may differ. The amendment did not impact previously reported AFFO or AFFO per share amounts.

AFFO represents net cash flows from operating activities adjusted to:

- exclude timing impacts of cash receipts and payments that may impact period-to-period comparability by including deductions for net finance expense and current income tax expense, and excluding deductions for interest paid, deductions for income taxes paid and changes in operating working capital,
- include our share of AFFO of equity-accounted investments and exclude distributions received from our equity-accounted investments which are calculated after the effect of non-operating activity equity-accounted investments debt payments,
- include government grants which represent a portion of operating returns on capital investment recognized in the period that they are either contractually obligated to be received by Capital Power or the period in which Capital Power has completed the necessary filing with the applicable tax authority to eliminate timing uncertainty due to administrative filing processes,
- exclude 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 except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2026	**2025**	**2026**	**2025**
Net cash flows from operating activities	**381**	**404**	**907**	**757**
Add (deduct):				
Interest paid	95	87	254	202
Change in fair value of derivatives reflected as cash settlement	4	–	10	7
Realized gain on settlement of interest rate derivatives	(12)	–	(12)	(17)
Distributions received from equity-accounted investments	(7)	(9)	(72)	(47)
Miscellaneous financing charges [1]	4	4	11	(2)
Income taxes recovered	(12)	(11)	(12)	(14)
Change in non-cash operating working capital	(26)	(77)	(39)	(23)
	46	(6)	140	106
Net finance expense [2]	(87)	(81)	(258)	(192)
Current income tax (expense) recovery [3]	(35)	16	(65)	72
Sustaining capital expenditures [4]	(87)	(44)	(232)	(85)
Preferred share dividends paid	(7)	(7)	(22)	(20)
Government grants [5]	50	50	224	60
Remove tax equity interests' respective shares of AFFO	1	(1)	–	(4)
AFFO from equity-accounted investments	43	38	98	101
Acquisition and integration costs [6]	–	3	(1)	41
Other non-recurring items [7]	1	(3)	(3)	(14)
AFFO	**306**	**369**	**788**	**822**
Weighted average number of common shares outstanding (millions)	157.4	155.3	156.8	148.6
AFFO per share ($)	**1.94**	**2.37**	**5.03**	**5.53**

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

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

[3] For the three and nine months ended September 30, 2025, excludes current income tax expense related to the partial divestiture of Quality Wind and Port Dover and Nanticoke Wind in 2024 as the amount is classified as an investing activity.

[4] Sustaining capital expenditures net of partner contributions of $1 million and $10 million for the three and nine months ended September 30, 2026, respectively, compared with $2 million and $8 million for the three and nine months ended September 30, 2025.

[5] For the nine months ended September 30, 2026, reflects recognition of $174 million in Clean Technology ITCs filed with the applicable tax authority, representing approximately 30% of eligible Canadian renewables project costs. For the three and nine months ended September 30, 2026 and September 30, 2025, reflects payments received from the Government of Alberta for the settlement of previously disputed off-coal compensation payments as described in the Company's 2025 annual consolidated financial statements.

[6] For the nine months ended September 30, 2026, current income tax recoveries of $1 million related to prior period acquisition and integration costs. For the three and nine months ended September 30, 2025, net of current income tax recoveries of $1 million and $2 million.

[7] For the three months ended September 30, 2026, other non-recurring items included $3 million of legal costs related to a contractor dispute concerning construction work at the Genesee Repowering project, offset by a $5 million recovery from the settlement of the FERC reactive supply and voltage control service overpayment provision and current income tax expense of $3 million. For the nine months ended September 30, 2026, other non-recurring items included $5 million of legal costs related to a contractor dispute at the Genesee Repowering project, offset by a $5 million recovery from the settlement of the FERC reactive supply and voltage control service overpayment provision and current income tax recoveries of $3 million associated with non-recurring items recognized in prior periods. For the three months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind virtual power purchase agreement (VPPA) of $5 million, net of current income tax recoveries of $8 million related to other non-recurring items recognized in the current and prior periods. For the nine months ended September 30, 2025, other non-recurring items reflect costs related to the termination of the Halkirk 2 Wind VPPA and end-of-life of Genesee coal operations of $5 million each, net of current income tax recoveries of $24 million related to other non-recurring items recognized in the current and prior periods.

FINANCIAL HIGHLIGHTS

($ millions, except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2026	**2025**	**2026**	**2025**
Revenues and other income	831	1,213	2,776	2,642
Net income	67	153	39	172
Net income attributable to shareholders of the Company	67	154	38	173
Basic earnings per share ($)	0.37	0.94	0.09	1.02
Diluted earnings per share ($) [1]	0.37	0.94	0.09	1.01
Adjusted EBITDA [2]	553	477	1,308	1,166
AFFO [2]	306	369	788	822
AFFO per share ($) [2]	1.94	2.37	5.03	5.53
Net cash flows from operating activities	381	404	907	757
Purchase of property, plant and equipment and other assets, net	167	147	642	576
Dividends per common share, declared ($)	0.7048	0.6910	2.0868	1.9948
Dividends per Series 1 preferred share, declared ($)	0.3099	0.1638	0.9297	0.4914
Dividends per Series 3 preferred share, declared ($)	0.4288	0.4288	1.2863	1.2863
Dividends per Series 5 preferred share, declared ($)	0.4144	0.4144	1.2433	1.2433

	As at	
	September 30, 2026	**December 31, 2025**
Loans and borrowings including current portion	6,805	6,730
Total assets	15,441	15,441

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

[2] 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.

Overall, the results for the third quarter and year-to-date are consistent with the Company's strategic priorities. Contributions from the U.S. flexible generation facilities acquired in 2025 reduced the Company's reliance on Alberta market conditions and offset the impact of softer Alberta pool prices and a higher level of outages across the fleet. The Company also continued to contract capacity from its existing fleet, including the long-term ESA with Meta entered into in July 2026 and the extension of the Arlington Valley tolling agreement earlier in the year, which increase the Company's contractedness while maintaining the Company's exposure to potential upside from Alberta power prices and its ability to pursue further commercial opportunities at the Genesee site. Growth projects under construction in Ontario and the U.S. are being funded from available liquidity, and tax equity financing, while maintaining the Company's dividend growth targets. Regulatory and policy developments in the quarter in Canada and the U.S. were largely supportive of the Company's strategy, as governments and system operators in each of its core markets advanced measures to accelerate the connection of data centres and other large loads and reduced emissions and permitting requirements for natural gas generation. These and other developments are discussed under Regulatory and Government Matters.

Revenues and other income were $831 million for the three months ended September 30, 2026, compared with $1,213 million in the prior year. The decrease was due to unfavourable changes in unrealized fair value on commodity derivatives and emission credits, primarily in the U.S. flexible generation segment. Excluding these non-cash fair value changes, revenues and other income increased, driven by higher contributions from the U.S. flexible generation segment, where stronger PJM pricing and summer demand at Hummel Station and Rolling Hills and higher contracted revenues at Arlington Valley more than offset less favourable hedge settlements at La Paloma.

For the nine months ended September 30, 2026, revenues and other income increased to $2,776 million from $2,642 million, as a full period of contributions from Hummel Station and Rolling Hills, acquired in June 2025, more than offset unfavourable unrealized fair value change. Revenues in the Canada flexible generation segment were modestly lower, as contributions from the Ontario BESS projects, Goreway and portfolio optimization largely offset lower Alberta spot power prices and generation, while the renewables segments were consistent with the prior year.

Net income was $67 million and $39 million for the three and nine months ended September 30, 2026, respectively, compared with $153 million and $172 million in the corresponding periods of 2025. Higher adjusted EBITDA, driven by the U.S. flexible generation segment as discussed below, and higher acquisition and integration costs in 2025 due to the Hummel Station and Rolling Hills acquisition was more than offset by:

- unfavourable changes in unrealized fair value on commodity derivatives and emission credits, primarily in the U.S. flexible generation segment,
- higher depreciation and amortization, reflecting a full period of ownership of Hummel Station and Rolling Hills, the Ontario BESS projects and Halkirk 2 Wind reaching commercial operation, and the derecognition of the remaining net book value of previously capitalized costs, and
- higher net finance expense, reflecting debt issued to fund the June 2025 acquisition and construction activities, lower finance income from lower cash balances and lower capitalized interest.

The year-to-date decrease was further impacted by lower income from equity-accounted investments, primarily due to a forced outage at Harquahala, an unfavourable change in foreign exchange on U.S. dollar denominated debt prior to its designation as a net investment hedge in the second quarter of 2026, and higher corporate expenses discussed below. These were partially offset by acquisition and integration costs incurred in 2025 related to the Hummel Station and Rolling Hills acquisition that did not recur.

Basic and diluted earnings per share changes were driven by the same factors as net income, and the changes from period to period in the weighted average number of common shares outstanding.

Adjusted EBITDA was $553 million and $1,308 million for the three and nine months ended September 30, 2026, respectively, compared with $477 million and $1,166 million in the corresponding periods in 2025. The increases were primarily due to:

- higher contributions from the Hummel Station and Rolling Hills facilities acquired in June 2025, reflecting stronger PJM power prices and summer demand in the third quarter and a full nine months of operations in 2026,
- higher results in the Canada flexible generation segment, as favourable portfolio optimization, higher generation and pricing at Goreway, and contributions from the Ontario BESS projects that commenced operations in September 2025 more than offset the impact of lower Alberta spot power prices and lower generation,
- partially offset by a lower contribution from La Paloma, where the financial hedges entered into following its acquisition settled less favourably than in 2025.

The year-to-date increase was partially offset by higher corporate expenses reflecting higher staff costs and costs associated with strategic initiatives, partially offset by lower equity-settled share-based compensation in 2026.

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

AFFO was $306 million and $788 million for the three and nine months ended September 30, 2026, respectively, compared with $369 million and $822 million in the corresponding periods in 2025. Despite higher adjusted EBITDA, as described above, AFFO for both the quarter and year-to-date periods was impacted by the following:

- higher sustaining capital expenditures, primarily reflecting the heavy maintenance schedule for the Alberta fleet, rotor replacements at Rolling Hills and Harquahala, and a full year of planned maintenance at Hummel Station and Rolling Hills,
- higher net finance expense, as described above,
- current income tax expense of $35 million and $65 million for the three and nine months ended September 30, 2026, respectively, compared with income tax recoveries of $16 million and $72 million in the corresponding periods of 2025, reflecting higher taxable income due to lower tax depreciation, and
- the non-cash straight-line recognition of capacity payments under the Arlington Valley summer tolling agreement, which contributed favourably to adjusted EBITDA, and which did not affect AFFO,
- the year-to-date impacts were partially offset by the recognition of $174 million in Clean Technology ITCs for eligible Canadian renewables projects in the second quarter of 2026.

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

Purchases of property, plant and equipment and other assets are discussed in Liquidity and Capital Resources.

SIGNIFICANT EVENTS

Meta Platforms, Inc. ESA

In July, Capital Power announced that it entered into a long-term (greater than 10 years) ESA for 250 MW of capacity and energy in support of a data centre in Sturgeon County, Alberta being developed by Meta. The load from the project is anticipated to be in service in the back half of 2028.

Tax equity financing

Capital Power's Hornet Solar and Bear Branch Solar projects reached mechanical completion on July 10, 2026 and September 16, 2026, respectively. The Company received approximately $26 million (US$18 million) for Hornet Solar and $9 million (US$7 million) for Bear Branch Solar in tax equity financing, net of issue costs of $6 million (US$4 million) associated with the financings in exchange for Class A interests in project subsidiaries.

Tax equity financing represents the contribution made by the project investor, adjusted for earnings, tax benefits and cash distributions realized/paid over time. The maturity dates of these obligations are subject to change and are driven by the dates on which the project investor reaches the agreed upon target rate of return. In accordance with the Company's material accounting policies (as described in the 2025 annual consolidated financial statements), the amounts paid by the project investors for their equity stakes are classified as loans and borrowings on the consolidated statements of financial position until the projects have yielded an agreed-upon target rate of return to the project investors.

Kevin MacIntosh appointed Chief Financial Officer

On February 19, 2026, Kevin MacIntosh was appointed as Chief Financial Officer of the Company, effective March 16, 2026. Mr. MacIntosh has over 30 years of experience as a finance leader working in large, complex organizations within the global energy industry and brings expertise across multi-jurisdictional operations, cross-border transactions, energy trading and diverse regulatory landscapes.

Arlington Valley tolling agreement extension and increased summer capacity

In January 2026, Capital Power extended its summer tolling agreement for the Arlington Valley facility with the current counterparty, an investment-grade utility. The agreement extends the existing 2031 agreement through October 2038 providing 13 years of contracted revenue and positioning Capital Power for continued growth and value creation in the U.S. southwest. The 6-month contract structure enables the facility to capture increasing merchant value during the winter months, while retaining the stability of contracted summer revenues. The facility is expected to realize a full year adjusted EBITDA uplift of approximately US$70 million annually by 2032, inclusive of the uprate. The uprate is expected to contribute approximately US$8 million per year adjusted EBITDA over the life of the asset, starting in 2027.

As part of this agreement, the facility will undergo a 35 MW capacity uprate to summer capacity; 10 MW were added in 2026 and an additional 25 MW will be added in 2027. This investment will strengthen Arlington's ability to provide reliable power during Arizona's peak summer demand.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and nine months ended September 30, 2026, compared with 2025 are presented below followed by further discussion of these items.

($ millions)	Three months		Nine months	
Consolidated net income for the periods ended September 30, 2025		**153**		**172**
Increase (decrease) in adjusted EBITDA [1]:				
Canada flexible generation	27		13	
Canada renewables	3		2	
U.S. flexible generation	44		172	
U.S. renewables	—		(4)	
Corporate	2	76	(41)	142
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(102)		(62)
Increase in depreciation and amortization expense		(50)		(134)
Change in foreign exchange gains or losses		9		(36)
Increase in other items [2]		(8)		(32)
Increase in net finance expense		(3)		(65)
Increase in loss on disposals and other transactions		(12)		(5)
Acquisition and integration costs		4		41
Non-recurring items		2		4
Decrease in income before tax		(84)		(147)
(Increase) decrease in income tax expense		(2)		14
Decrease in net income		(86)		(133)
Consolidated net income for the periods ended September 30, 2026		**67**		**39**

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

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

Results by segment and other

	Three months ended September 30,							
	2026	2025	2026	2025	2026	2025	2026	2025
	Electricity generation (GWh) [1]		Availability (%) [2]		Revenues and other income ($ millions) [3,4,5]		Adjusted EBITDA ($ millions) [3,4,5]	
Total electricity generation, average availability and facility revenues	14,485	13,374	93	93	911	838		
Canada flexible generation	5,256	5,029	97	95	532	533	208	181
Canada renewables	541	456	94	97	28	23	21	18
Total Canada	**5,797**	**5,485**	**96**	**96**	**560**	**556**	**229**	**199**
U.S. flexible generation	8,291	7,550	91	93	540	496	351	307
U.S. renewables	397	339	89	91	27	27	15	15
Total U.S.	**8,688**	**7,889**	**91**	**91**	**567**	**523**	**366**	**322**
Corporate [6]					–	5	(42)	(44)
Unrealized changes in fair value of commodity derivatives and emission credits					(296)	129		
Consolidated revenues and other income and adjusted EBITDA					**831**	**1,213**	**553**	**477**

	Nine months ended September 30,							
	2026	2025	2026	2025	2026	2025	2026	2025
	Electricity generation (GWh) [1]		Availability (%) [2]		Revenues and other income ($ millions) [3,4,5]		Adjusted EBITDA ($ millions) [3,4,5]	
Total electricity generation, average availability and facility revenues	36,090	31,951	91	92	2,568	1,959		
Canada flexible generation	13,163	13,761	93	93	1,561	1,585	567	554
Canada renewables	1,848	1,610	94	97	86	81	80	78
Total Canada	**15,011**	**15,371**	**93**	**94**	**1,647**	**1,666**	**647**	**632**
U.S. flexible generation	19,535	15,151	89	92	1,457	959	739	567
U.S. renewables	1,544	1,429	90	90	105	107	69	73
Total U.S.	**21,079**	**16,580**	**89**	**91**	**1,562**	**1,066**	**808**	**640**
Corporate [6]					13	36	(147)	(106)
Unrealized changes in fair value of commodity derivatives and emission credits					(446)	(126)		
Consolidated revenues and other income and adjusted EBITDA					**2,776**	**2,642**	**1,308**	**1,166**

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

[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 results by segment and other, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios.

[4] 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. The facilities' revenues and other income are not included in the above results. Capital Power's share of each facility's adjusted EBITDA is included in adjusted EBITDA above.

[5] Capital Power's share of revenue and adjusted EBITDA from equity-accounted investments was $134 million and $69 million and $418 million and $163 million for the three and nine months ended September 30, 2026, respectively, compared with $135 million and $62 million and $405 million and $175 million for the three and nine months ended September 30, 2025, respectively.

[6] Corporate revenues are partially offset by interplant category eliminations.

Average power and natural gas energy pricing

Average prices	Units	Three months ended September 30, 2026	Three months ended September 30, 2025	Nine months ended September 30, 2026	Nine months ended September 30, 2025
Power					
Alberta AESO	($/MWh)	35.52	51.30	32.40	43.90
Alberta realized power price average [1]	($/MWh)	76.83	72.68	81.71	73.45
PJM - Western Hub [2]	(US$/MWh)	41.71	36.04	51.03	37.01
PJM - AEP Dayton Hub [2]	(US$/MWh)	60.45	43.47	58.13	44.77
PJM realized power price average [1,2,3]	(US$/MWh)	47.59	39.58	49.16	40.75
CAISO SP15	(US$/MWh)	42.93	37.93	26.55	30.93
California realized power price average [1,4]	(US$/MWh)	88.67	117.36	132.38	104.16
Natural gas					
Alberta AECO	($/GJ)	1.50	0.63	1.66	1.43
Alberta realized natural gas price average [5]	($/GJ)	3.26	2.27	3.50	2.47
PJM - Transco Leidy [2]	(US$/MMBtu)	1.82	2.16	3.27	2.19
PJM - Tetco ELA [2]	(US$/MMBtu)	2.62	2.83	3.38	2.84
PJM realized natural gas price average [2,5]	(US$/MMBtu)	2.97	2.57	3.75	2.53
SoCal Border	(US$/MMBtu)	2.53	2.66	1.89	2.72
California realized natural gas price average [5]	(US$/MMBtu)	5.42	6.62	8.67	5.75

[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] Pricing for the three and nine months ended September 30, 2025 is from the date of the acquisitions of the Hummel Station and Rolling Hills facilities on June 9, 2025.

[3] Realized power price excludes PJM capacity revenues.

[4] Realized power price excludes California resource adequacy revenues.

[5] Realized natural gas price is the average aggregate price realized through the purchase of natural gas to fuel the Company's generation, including spot market purchases, the Company's commercial contracted arrangements, and portfolio optimization activities. When long-term forward portfolio optimization hedges are transacted, they reflect the market's expectation for future period pricing. Ultimately, spot pricing may vary from expected forward pricing due to a number of factors, resulting in realized gas prices in a given period that can differ materially from spot pricing.

Canada flexible generation

Alberta spot price averaged $36 and $32 per MWh, respectively, for the three and nine months ended September 30, 2026, compared to $51 and $44 per MWh in the same periods last year. Higher available supply and significant renewables generation lowered Alberta spot power pricing.

Generation for the three months ended September 30, 2026 was higher compared to the previous year mainly due to higher generation at Goreway due to strong demand and prices in Ontario. Generation for the nine months ended September 30, 2026 was lower compared to the same period in the prior year while availability remained consistent due to the following net effect:

- lower generation at Genesee Generation Station, Joffre and Shepard due to outages, and lower dispatch on the rest of the Alberta fleet due to decreased power prices, partially offset by
- higher generation at Goreway due to higher demand due to weather, pricing and strong demand, and
- generation from the Ontario BESS projects, which began commercial operation in September 2025.

Revenues and other income were consistent quarter-over-quarter and lower year-over-year from lower Alberta spot power pricing, offset by portfolio optimization, contributions from the Ontario BESS projects and higher generation and realized pricing at Goreway.

Adjusted EBITDA was favourable quarter-over-quarter and year-over-year due to contributions from the Ontario BESS projects and Goreway, offset by lower Alberta captured spark spreads.

Canada renewables

Generation was higher for the three and nine months ended September 30, 2026, compared to the same periods in 2025 due to the addition of Halkirk 2 Wind which achieved commercial operation in the fourth quarter of 2025. Revenues and other income and adjusted EBITDA were higher year-over-year, primarily due to the contribution from Halkirk 2 Wind which was slightly offset by lower Alberta captured pool prices.

U.S. flexible generation

Generation for the three months ended September 30, 2026 increased compared to the same period in 2025 due to a strong summer dispatch, partially offset by lower generation at Harquahala due to equipment outages. Generation for the nine months ended September 30, 2026 was higher than the prior year due to the acquisitions of the Hummel Station and Rolling Hills facilities in June 2025, partially offset by lower dispatch of the other U.S. flexible generation facilities reflecting lower demand amid milder temperatures, and increased imports into the California market at La Paloma that reduced natural gas-fired generation across the California Independent System Operator.

Availability was slightly lower quarter-over-quarter reflecting outages at Harquahala, partially offset by improved availability at Decatur. Availability was slightly lower year-over-year, reflecting gas turbine outages at the Rolling Hills and Harquahala facilities.

Revenues and other income for the three and nine months ended September 30, 2026 exceeded prior year results primarily due to the Hummel Station and Rolling Hills facilities acquired in June 2025 and higher contracted revenues at Arlington Valley. These increases were partially offset by portfolio optimization, lower year-to-date dispatch at La Paloma and increased maintenance outages in 2026 which resulted in lower capacity and variable revenues compared to the same periods in 2025. Realized prices at La Paloma continued to exceed spot prices, reflecting hedges entered into following the acquisition under market conditions that differed materially from those prevailing in 2026. While these hedges remained favourable, their contribution was lower than in 2025.

Adjusted EBITDA for the three and nine months ended September 30, 2026 was further impacted by strong generation and results from Midland Cogeneration Venture tempered by the impacts of higher maintenance costs due to equipment outages at Harquahala, Rolling Hills and Decatur in the second and third quarters of 2026.

U.S. renewables

Higher generation and consistent availability year-over-year were offset by unfavourable power prices resulting in consistent revenues and other income compared to the same periods in 2025. Adjusted EBITDA was further impacted by increased turbine blade maintenance expenses at Cardinal Point Wind.

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 nine months ended September 30, 2026 were lower compared to the same periods in 2025, primarily due to higher insurance proceeds and government grant revenues for the SMR project received in 2025. Adjusted EBITDA for the nine months ended September 30, 2026 was lower compared with the same period in 2025 primarily due to the noted insurance proceeds and government grant revenues, and costs associated with various strategic initiatives, partially offset by the noted lower equity-based compensation.

Unrealized changes in fair value of commodity derivatives and emission credits

($ millions)	Three months ended September 30,			
	2026	2025	2026	2025
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income [1]**		**Income before tax [1]**	
Unrealized (losses) gains on power derivatives	(263)	114	(156)	75
Unrealized (losses) gains on natural gas derivatives	(41)	18	65	(80)
Unrealized gains (losses) on emission derivatives and credits held for trading	8	(3)	2	18
	(296)	**129**	**(89)**	**13**

($ millions)	Nine months ended September 30,			
	2026	2025	2026	2025
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income [1]**		**Income before tax [1]**	
Unrealized losses on power derivatives	(416)	(115)	(294)	(115)
Unrealized (losses) gains on natural gas derivatives	(43)	(8)	55	(22)
Unrealized gains (losses) on emission derivatives and credits held for trading	13	(3)	1	(39)
	(446)	**(126)**	**(238)**	**(176)**

[1] Revenues and other income and adjusted EBITDA 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 nine months ended September 30, 2026, we recorded unrealized losses on power derivatives of $156 million and $294 million, respectively, reflecting increasing forward prices on net forward sale contracts for our PJM and California facilities, partially offset by decreasing forward prices on net forward sale contracts at our U.S. wind facilities and in Alberta. During the comparable prior year periods, we recorded unrealized gains of $75 million for the three months ended September 30, 2025 due to decreasing forward prices in California and unrealized losses of $115 million for the nine months ended September 30, 2025, driven by increasing forward prices on net forward sale contracts in Alberta.

During the three months ended September 30, 2026, we recognized unrealized gains on natural gas derivatives of $65 million due to increasing forward prices on forward purchase contracts, and unrealized gains of $55 million in the nine months ended September 30, 2026, reflecting increasing forward pricing on net forward buy contracts in SoCal offset by Alberta markets. During the three and nine months ended September 30, 2025, we recognized unrealized losses of $80 million and $22 million, respectively, driven by decreasing forward prices on forward purchase contracts.

During the three and nine months ended September 30, 2026, we recognized unrealized gains of $2 million and $1 million, respectively, on U.S. emissions derivatives, primarily due to declining forward prices. In the comparable prior year periods, we recognized unrealized gains of $18 million during the three months ended September 30, 2025 driven by increases in forward prices, and unrealized losses of $39 million during the nine months ended September 30, 2025 resulting from decreased forward prices on net forward purchases in U.S. emissions derivatives.

Consolidated other expenses

($ millions)	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Net finance expense	(95)	(92)	(282)	(217)
Depreciation and amortization	(207)	(157)	(555)	(421)
Foreign exchange gain (loss)	2	(7)	(20)	16
Loss on disposals and other transactions	(17)	(5)	(17)	(12)
Income tax expense	(37)	(35)	(15)	(29)

Net finance expense

Higher net finance expense for the nine months ended September 30, 2026 compared with the same period in the prior year largely reflects higher interest expense due to higher loans and borrowings under the $600 million credit facility, and on the $1.7 billion senior notes issued during 2025 to fund the Hummel Station and Rolling Hills acquisition, and lower interest income earned on Canadian cash balances held in the prior year. Capitalized interest was lower during 2026 following the completion of the Ontario BESS and Halkirk 2 Wind projects in 2025, partly offset by capitalized interest on the East Windsor Expansion and North Carolina solar projects in the current year. Accretion expense also increased as a result of updated decommissioning cost estimates completed at the end of 2025. Net finance expense was consistent quarter-over-quarter.

Depreciation and amortization

Higher depreciation and amortization for the three and nine months ended September 30, 2026 reflects a full period of ownership of Hummel Station and Rolling Hills, and the Ontario BESS projects and Halkirk 2 Wind which reached commercial operation in 2025, and the derecognition of the remaining net book value of previously capitalized costs.

Foreign exchange gain (loss)

The foreign exchange losses for the nine months ended September 30, 2026, compared to gains in the same period in 2025, were primarily due to the strengthening of the U.S. dollar against the Canadian dollar during the current year, which resulted in unrealized losses on foreign exchange hedges entered into during 2026. In addition, Capital Power designated certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations, resulting in the associated foreign exchange loss being recognized in other comprehensive income rather than net income. These hedge relationships were not in place in the comparable 2025 periods when the U.S. dollar weakened against the Canadian dollar.

Income tax expense

Higher income tax expense for the three months ended September 30, 2026, compared with the respective period in 2025, was primarily due to varying applicable tax rates on consolidated net income before tax. Lower income tax expense for the nine months ended September 30, 2026, compared with the respective period in 2025, was primarily due to a decrease in consolidated net income before tax.

FINANCIAL POSITION

Changes in the consolidated statements of financial position from December 31, 2025 to September 30, 2026 were as follows:

($ millions)	September 30, 2026	December 31, 2025
Assets		
Current assets	1,557	1,542
Non-current assets:		
Property, plant and equipment	11,485	11,253
Equity-accounted investments	1,048	1,064
Intangible assets and goodwill	589	620
Right-of-use assets	145	136
Derivative financial instruments	314	373
Government grant receivable	137	320
Deferred tax assets	55	26
Other assets	111	107
Total assets	15,441	15,441
Liabilities and equity		
Current liabilities	1,921	1,635
Non-current liabilities:		
Derivative financial instruments	723	719
Loans and borrowings	6,323	6,383
Lease liabilities	168	154
Deferred tax liabilities	876	904
Provisions	434	504
Deferred revenue and other liabilities	265	293
Total liabilities	10,710	10,592
Share capital	5,127	5,036
Deficit	(721)	(349)
Other reserves	332	170
Equity attributable to shareholders of the Company	4,738	4,857
Non-controlling interests	(7)	(8)
Total equity	4,731	4,849
Total liabilities and equity	15,441	15,441

Net working capital decreased from December 31, 2025 to September 30, 2026 by $271 million, mainly driven by the net impacts of:

- increased net current derivative financial instrument liabilities (see Unrealized changes in fair value of commodity derivatives and emission credits),
- reclassifying the $400 million unsecured senior medium-term notes due in 2027 from non-current to current, partially offset by the repayment of the Company's $160 million private placement and $91 million CPLP unsecured notes in 2026, and
- higher trade receivables due to the government grants receivable reclassification to current assets as noted below, partially offset by lower accrued revenue for Goreway,
- partially offset by lower income taxes recoverable as current year tax expense reduced cash tax installments currently on account and the Clean Technology ITCs were reclassified to trade receivables.

Government grants receivable decreased from December 31, 2025 to September 30, 2026 due to the Clean Technology ITCs reclassification to current assets.

Property, plant and equipment increased from December 31, 2025 to September 30, 2026 primarily due to growth capital expenditures for the North Carolina solar, East Windsor Expansion and Arlington Valley uprate projects, and sustaining capital expenditures, combined with the impact of a stronger U.S. dollar on foreign currency translation of U.S. assets, partially offset by depreciation expense.

Provisions decreased from December 31, 2025 to September 30, 2026 due to the settlement of FERC provision for reactive supply and voltage control from generation sources service overpayments which was assumed as part of the acquisition of Hummel Station and due to the change in discount rate for decommissioning provisions across the fleet.

The Company has $1.6 billion of available liquidity from credit facilities if needed to meet obligations as they become due (2025 - $1.8 billion) (see Liquidity and Capital Resources).

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Nine months ended September 30,		
Cash inflows (outflows)	**2026**	**2025**	**Change**
Operating activities	907	757	150
Investing activities	(587)	(3,477)	2,890
Financing activities	(293)	2,082	(2,375)

Operating activities

Cash flows from operating activities for the nine months ended September 30, 2026 were higher than the same period in 2025 mainly due to the net impact of:

- cash inflows from the contributions of the Hummel Station and Rolling Hills facilities acquired in June 2025,
- increased distributions received from equity-accounted investments,
- a favourable change in operating non-cash working capital, and
- increased interest paid on higher loans and borrowings due to the $1.7 billion senior notes issued in the prior year to fund the acquisitions of the Hummel Station and Rolling Hills facilities, and increased draws on the credit facility in the current year.

Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2026 were lower compared with the same period in 2025 due to the acquisitions of the Hummel Station and Rolling Hills facilities in June 2025.

Financing activities

Cash flows (used in) from financing activities for the nine months ended September 30, 2026 were lower than the same period in 2025 due to proceeds received from the $1.7 billion senior notes issued and the bought deal offering and private placement in the prior year.

Capital expenditures and investments

($ millions)	Pre-2026 actual	Nine months ended September 30,	Balance of 2026 estimated [1,2]	Actual or projected total [2]	Targeted completion
Repowering of Genesee 1 and 2 [3]	1,554	18	2 - 78	1,574 to 1,650	Achieved commercial operations in the fourth quarter of 2024 and the project is substantially complete
Halkirk 2 Wind	323	(3)	–	320	Achieved commercial operations in the fourth quarter of 2025
Ontario growth projects	530	41	14	585	York and Goreway BESS completed in the third quarter of 2025 East Windsor Expansion in the fourth quarter of 2026 (revised from the third quarter of 2026)
Maple Leaf Solar	72	118	9	229	Second quarter of 2027 (revised from the first quarter of 2027)
Bear Branch Solar	51	51	4	106	Fourth quarter of 2026
Hornet Solar	151	48	11	210	Fourth quarter of 2026 (revised from the third quarter of 2026)
Commercial initiatives [4]	287	21	46		
Development sites and projects	64	–	–		
Subtotal growth projects		**294**	**86 - 162**		
Sustaining – plant maintenance		242			
Total capital expenditures [5]		**536**			
Emission credits held for compliance		33			
Capitalized interest		(22)			
Additions of property, plant and equipment and other assets		**547**			
Change in other non-cash investing working capital and non-current liabilities		95			
Purchase of property, plant and equipment and other assets, net		**642**			

[1] The Company's 2026 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 incurred post-commercial operations date, remain subject to the dispute resolution with the contractor described under Contingent Liabilities, Other Legal Matters and Provisions.

[4] Commercial initiatives are projects that increase capacity, improve efficiency, reduce emissions, extend a facility's commercial life, or modify a facility to meet new commercial requirements, but exclude routine maintenance or activities that sustain existing performance.

[5] 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

The Company's credit facilities consisted of:

($ millions)		At September 30, 2026			At December 31, 2025		
	Maturity timing	Total facilities	Credit facility utilization	Available	Total facilities	Credit facility utilization	Available
Committed credit facilities [1]	2028 - 2031	2,100	540	1,560	2,100	254	1,846
Bilateral demand credit facilities	N/A	1,417			1,402		
Letters of credit outstanding			626			604	
Demand credit facilities	N/A	25	13	12	25	–	25
		3,542	**1,179**	**2,363**	**3,527**	**858**	**2,669**

[1] Committed credit facilities include letters of credit, bankers' acceptances and bank loans outstanding. In June 2026, the Company extended its $1.5 billion revolving credit facility to 2031 and its $600 million revolving credit facility to 2028.

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 September 30, 2026, $123 million of bonds were issued under these facilities (December 31, 2025 - $99 million).

Capital Power has the following corporate credit ratings which were affirmed in April and May 2026:

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 for the payment of financial obligations is considered acceptable but the entity may be 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.

Off-statement of financial position arrangements

At September 30, 2026, Capital Power has $626 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements, and to satisfy legislated reclamation requirements and $123 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	
	September 30, 2026	**December 31, 2025**
Loans and borrowings	6,805	6,730
Lease liabilities [1]	177	162
Less cash and cash equivalents	(150)	(119)
Net debt	6,832	6,773
Share capital	5,127	5,036
Deficit and other reserves	(389)	(179)
Non-controlling interests	(7)	(8)
Total equity	4,731	4,849
Total capital	**11,563**	**11,622**

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

Capital Power uses shelf prospectuses to access debt and equity markets when conditions are favourable. On March 19, 2026, Capital Power filed a short-form base shelf prospectus and a medium term note (MTN) base shelf prospectus. The short-form base shelf prospectus allows Capital Power to 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. The MTN base shelf prospectus allows Capital Power to issue medium-term notes. Both prospectuses expire in April 2029.

If the Canadian and U.S. financial markets were to become unstable, Capital Power's ability to raise new capital, fulfill our financial obligations, and refinance debt under existing credit facilities and debt agreements may be negatively impacted. Capital Power is exposed to credit risk through various agreements, particularly those related to power purchase agreements, VPPAs, energy purchase agreements, energy supply contracts, and trading and supplier counterparties. While Capital Power actively monitors exposure to significant counterparties, there is no assurance that all counterparties will fulfill their obligations. 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 2025 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.

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. While final project costs remain subject to the outcome of the arbitration, the Genesee Repowering project achieved commercial operations in 2024 and is considered substantially complete.

RISKS AND RISK MANAGEMENT

For the nine months ended September 30, 2026, Capital Power's key enterprise risks and opportunities remained consistent with those described in our 2025 Integrated Annual Report. There were no material changes to principal risk factors or associated risk mitigation strategies during the quarter. Management has also assessed the effect of ongoing geopolitical conflicts, including between the U.S. and Iran, and determined that there has been no direct material impact on Capital Power's operations or risk profile to date.

REGULATORY AND GOVERNMENT MATTERS

Refer to the Regulatory and Government Matters discussion in the Company's 2025 Integrated Annual Report for further details that supplement the recent developments discussed below:

United States

Department of Energy (DOE)

In August 2026, the Trump administration issued Executive Order 14421, "Declaring a National Emergency to Secure the United States Bulk-Power System," which grants the DOE authority to restrict certain foreign-sourced equipment used in the U.S. bulk electric system on national security grounds. The order may impact future procurement decisions for generation, storage, and transmission interconnection projects, and could increase scrutiny of the country-of-origin for critical power system components. The Company continues to monitor supply-chain impacts to current operations and future development activities across our portfolio.

U.S. tariffs / United States-Mexico-Canada Agreement (USMCA)

In August 2026, trade discussions between Canada and the U.S. reached an impasse and the U.S. imposed 50% tariffs on roughly $20 billion of Canadian goods. Canada responded with counter-tariffs ranging from 15% to 50% on certain U.S. imports. These developments may increase the cost of raw materials used in power plant construction, and contribute to greater uncertainty across North American supply chains.

In July 2026, the U.S. indicated it would not pursue renewal of the USMCA with Canada and Mexico, instead opting to conduct annual reviews of the agreement. The USMCA will remain in force for a further 10 years unless one of the three signatory countries elects to withdraw.

The Company continues to monitor trade policy developments and to assess potential implications for procurement, construction and operating activities across its North American portfolio.

Federal Energy Regulatory Commission

In June 2026, FERC issued show-cause orders to all Regional Transmission Organizations and Independent System Operators, requiring them to justify or revise rules governing the interconnection and integration of large loads, including data centres. FERC indicated that existing tariffs may not adequately address these interconnection challenges. Responses to the orders were due by August 17, 2026 and stakeholder comments are due 30 days thereafter. The proceedings are expected to inform the frameworks under which large-load projects are integrated into wholesale markets. The Company continues to monitor the proceedings, including as they relate to opportunities to serve data centre demand across our U.S. footprint.

U.S. Clean Air Act - Maricopa County nonattainment and permitting matters

In September 2026, the U.S. Environmental Protection Agency (EPA) finalized its repeal of the 2024 power plant regulations that would have required certain gas, oil, and coal-fired generating units to mitigate carbon emissions beginning in 2032. Legal challenges to the repeal have been filed and the outcome remains uncertain. The Company continues to monitor U.S. federal emissions requirements for power plants.

In March 2026, the U.S. EPA determined that Maricopa County would have met the 2015 ozone standard absent emissions from outside the U.S., reducing the risk of reclassification to serious nonattainment and providing greater certainty for operations and expansion at Harquahala and Arlington Valley.

PJM market

Large-load integration and interconnection frameworks

In July 2026, the PJM Board issued a decisional letter on the Critical Issue Fast Path (CIFP) and directed PJM staff to file with FERC to establish a Reliability Backstop Procurement (RBP) mechanism. The Board also selected an Interim Resource Adequacy Service framework (IRAS) (formerly known as Connect and Manage) to address requests from data centres and other large-load customers seeking interconnection before adequate generation is available. The framework would allow certain large loads to connect to the grid, subject to potential curtailment during periods of capacity shortages, and includes mechanisms to support Bring Your Own New Generation arrangements. FERC has rejected the IRAS proposal and it is uncertain if and how this policy will be addressed going forward.

In June 2026, PJM concluded the CIFP process for RBP. PJM's proposal addresses the 2028/29 Base Residual Auction shortfall, through a pay-as-bid request for proposal with a $555/MW-day cap and 15-year contracts. Procurement volumes would be tied to the size of the shortfall and could be reduced if load-serving entities or states secure new supply outside the auction. Projects must be online by June 2032, with PJM prioritizing earlier commercial operation dates to lower levelized costs. The RBP will go forward subject to FERC approval.

These developments are expected to be beneficial for Capital Power's planned uprates at Rolling Hills and Hummel Station, while less helpful for larger expansion projects.

Capacity market developments and affordability measures

In February 2026, PJM's Board of Managers announced its intention to extend the capacity market price collar through 2030, subject to FERC approval with support from the White House National Energy Dominance Council and governors of PJM states.

Prices in the PJM July capacity auction for the 2028/2029 delivery year hit a $325/MW-day price cap across the region. The auction left PJM with a roughly 6.8 GW shortfall below the grid operator's 20% installed reserve margin target.

Canada

Impact Assessment Act (IAA)

In September 2026, the Government of Canada published *Regulations Amending the Physical Activities Regulations,* removing fossil fuel-fired power generating facilities from the Physical Activities Regulations under the IAA. Prior to this amendment, fossil fuel-fired power generation facilities over 200 MW were required to complete an Impact Assessment and approval from the Impact Assessment Agency before proceeding.

Canada-Alberta Memorandum of Understanding (MOU)

In May 2026, Alberta and the Government of Canada signed an implementation agreement, advancing priorities from the 2025 MOU, including updates to industrial carbon pricing, a commitment to hold the Clean Electricity Regulations in abeyance in Alberta, measures to de-risk investment, next steps for carbon capture and storage, and a pipeline to the West Coast. The Government of Canada also revised the carbon pricing trajectory nationally by lowering the carbon price and extending the schedule from 2030 to 2040. Capital Power is engaged in consultations regarding the implementation of changes to the Technology Innovation and Emissions Reduction regulation, specifically how the price floor regulations will be developed and managed. The Government of Alberta is set to announce regulations prior to the end of 2026.

National Electricity Strategy Discussion Paper

In May 2026, the Government of Canada released Powering Canada Strong: A National Strategy for an Electrified Canadian Economy, a consultation paper focused on expanding and modernizing the electricity system to support growing demand from data centres, industrial growth, and economy-wide electrification. The strategy recognizes the continued role of natural gas generation in maintaining reliability, affordability, and system flexibility and includes commitments to amend the Clean Electricity Regulations, expand investment tax credits for intra-provincial transmission, and explore regional integration. Capital Power is participating in the consultation process.

Alberta

Data Centre Regulation and Phase II Process

In September 2026, the Alberta Electric System Operator (AESO) published a stakeholder update indicating that the Large Load Phase II process will now be published this fall, rather than August 2026. The Phase II process is expected to build on the Government of Alberta's June 2026 Data Centre Regulation, which provided the AESO with additional authority to enable timely and structured data centre development and greater clarity on Alberta's Bring Your Own Generation model. This regulation enables the AESO to designate and prioritize tethering arrangements that link data centre load with generation which will be part of the AESO's forthcoming Phase II large load interconnection process. Management continues to engage in this process.

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

Following Ministerial approval of the REM ISO Rules in March 2026, which established the high-level REM framework, the AESO continued implementation activities in preparation for the anticipated 2028 market transition. In September 2026, the AESO released the first of four planned stakeholder engagement windows on proposed amendments to the REM ISO Rules, supporting ISO manuals and glossary definitions required to operationalize the market design and align with ongoing market system development. Through its Market Participant Readiness program, the AESO has released its first public learning module and established an IT Systems Working Group, in which Capital Power is participating. Management continues to participate in stakeholder engagements, monitor developments, and assess potential implications as implementation advances.

Bill 30: The Expedited Approvals Act

In spring 2026, Bill 30 received Royal Assent with the intention of accelerating regulatory decisions for major energy, mining and industrial developments with a minimum capital cost of $250 million by enforcing a mandatory 120-business-day timeline. The Government of Alberta is currently developing the process for which projects can apply, with plans to formalize the process by the end of 2026. Capital Power continues to engage with the Government of Alberta regarding the intake process, and to determine whether certain projects may apply.

Ontario

Data Centre Playbook

In August 2026, the Government of Ontario released a draft Data Centre Playbook and supporting consultation materials outlining a proposed framework for assessing and connecting new data centres to the electricity grid. The proposal contemplates measures intended to ensure data centres support provincial economic priorities while recovering electricity system costs associated with their operations. Management continues to monitor developments and assess potential implications for electricity demand growth, system planning, and future generation investment opportunities in Ontario.

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 2025 Integrated Annual Report.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at September 30, 2026 and December 31, 2025 were as follows:

($ millions)		September 30, 2026		December 31, 2025	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	150	150	119	119
Trade and other receivables [2]	N/A	576	576	736	736
Government grant receivable [3]	Level 2	360	348	406	389
Fair value through profit or loss					
Derivative financial instruments [3]	See below	585	585	655	655
Fair value through other comprehensive income					
Derivative financial instruments [3]	See below	58	58	33	33
Financial liabilities:					
Amortized cost					
Trade and other payables	N/A	798	798	789	789
Loans and borrowings [3]	Level 2	6,805	6,926	6,730	7,052
Fair value through profit or loss					
Derivative financial instruments [3]	See below	1,172	1,172	980	980
Fair value through other comprehensive income					
Derivative financial instruments [3]	See below	2	2	13	13

[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 nine months ended September 30, 2026 to our risk management and hedging activities as described in our 2025 Integrated Annual Report.

The derivative financial instruments assets and liabilities held at September 30, 2026 compared with December 31, 2025 and used for risk management purposes were measured at fair value and consisted of the following:

($ millions)		At September 30, 2026					
	Fair value hierarchy level	Commodity cash flow hedges	Commodity non-hedges	Interest rate cash flow hedges	Interest rate non-hedges	Foreign exchange non-hedges	Total
Derivative financial instruments assets	Level 2	24	305	–	–	–	329
	Level 3	10	278	24	2	–	314
		34	583	24	2	–	643
Derivative financial instruments liabilities	Level 2	(1)	(437)	–	–	(13)	(451)
	Level 3	(1)	(720)	–	–	(2)	(723)
		(2)	(1,157)	–	–	(15)	(1,174)
Net derivative financial instruments assets (liabilities)		**32**	**(574)**	**24**	**2**	**(15)**	**(531)**

($ millions)		At December 31, 2025				
	Fair value hierarchy level	Commodity cash flow hedges	Commodity non-hedges	Interest rate cash flow hedges	Foreign exchange non-hedges	Total
Derivative financial instruments assets	Level 2	29	584	4	1	618
	Level 3	–	70	–	–	70
		29	654	4	1	688
Derivative financial instruments liabilities	Level 2	(11)	(642)	(2)	–	(655)
	Level 3	–	(338)	–	–	(338)
		(11)	(980)	(2)	–	(993)
Net derivative financial instruments assets (liabilities)		**18**	**(326)**	**2**	**1**	**(305)**

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. For foreign currency denominated debt designated as a net investment hedge of foreign operations, foreign exchange gains and losses are deferred within accumulated other comprehensive income (loss) and are reclassified to net income as foreign exchange gains and losses, as appropriate, on the disposal of the foreign operation.

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

There were no significant changes in Capital Power's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2026 that have materially affected or are reasonably likely to materially affect disclosures of required information and internal control over financial reporting.

SUMMARY OF QUARTERLY RESULTS

	Three months ended							
	Sep 2026	**Jun 2026**	**Mar 2026**	**Dec 2025**	**Sep 2025**	**Jun 2025**	**Mar 2025**	**Dec 2024**
Electricity generation (GWh)								
Canada flexible generation	5,256	3,345	4,562	4,960	5,029	3,933	4,799	3,596
Canada renewables	541	622	685	642	456	557	597	704
U.S. flexible generation	8,291	5,600	5,644	6,519	7,550	4,026	3,575	4,540
U.S. renewables	397	570	577	544	339	506	584	568
Total electricity generation	14,485	10,137	11,468	12,665	13,374	9,022	9,555	9,408
Availability (%)								
Canada flexible generation	97	88	94	92	95	91	94	87
Canada renewables	94	93	96	90	97	97	96	96
U.S. flexible generation	91	86	90	88	93	96	85	88
U.S. renewables	89	90	91	90	91	89	90	93
Total average availability	93	87	92	90	93	93	90	89
Revenues and other income ($ millions)								
Canada flexible generation	532	447	582	596	533	472	580	523
Canada renewables	28	28	30	30	23	28	30	56
U.S. flexible generation	540	396	521	457	496	213	250	198
U.S. renewables	27	42	36	39	27	39	41	37
Corporate [1]	—	5	8	4	5	17	14	9
Unrealized changes in fair value of commodity derivatives and emission credits	(296)	(178)	28	(48)	129	(328)	73	30
Total revenues and other income	**831**	**740**	**1,205**	**1,078**	**1,213**	**441**	**988**	**853**
Adjusted EBITDA [2]								
Canada flexible generation [3]	208	165	194	187	181	166	207	200
Canada renewables [3]	21	26	33	33	18	27	33	42
U.S. flexible generation [3]	351	188	200	208	307	141	119	123
U.S. renewables	15	31	23	30	15	27	31	26
Corporate	(42)	(59)	(46)	(44)	(44)	(39)	(23)	(61)
Total adjusted EBITDA [2]	**553**	**351**	**404**	**414**	**477**	**322**	**367**	**330**

[1] Revenues are partially 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 equity-accounted investment. Canada renewables include adjusted EBITDA from Quality Wind and Port Dover and Nanticoke Wind equity-accounted investments. U.S. flexible generation includes adjusted EBITDA from Midland Cogeneration and Harquahala equity-accounted investments.

Financial highlights

($ millions except per share amounts)	Three months ended							
	Sep 2026	Jun 2026	Mar 2026	Dec 2025	Sep 2025	Jun 2025	Mar 2025	Dec 2024
Revenues and other income	831	740	1,205	1,078	1,213	441	988	853
Net income	67	(43)	15	(13)	153	(131)	150	242
Net income (loss) attributable to shareholders of the Company	67	(44)	15	(13)	154	(132)	151	240
Basic earnings (loss) per share	0.37	(0.33)	0.04	(0.12)	0.94	(0.92)	1.03	1.76
Diluted earnings (loss) per share [1]	0.37	(0.33)	0.04	(0.12)	0.94	(0.92)	1.03	1.75
Adjusted EBITDA [2,3]	553	351	404	414	477	322	367	330
AFFO [2]	306	328	154	244	369	235	218	182
AFFO per share ($) [2]	1.94	2.09	0.98	1.57	2.37	1.55	1.57	1.38
Net cash flows from operating activities	381	214	312	205	404	143	210	438
Purchase of property, plant and equipment and other assets, net	167	211	264	288	147	141	288	395

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

[2] 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.

[3] 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. Due to the proximity to December 31, 2024, adjusted EBITDA relating to the equity-accounted investments period during the quarter was immaterial.

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 2025 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							
	Sep 2026	**Jun 2026**	**Mar 2026**	**Dec 2025**	**Sep 2025**	**Jun 2025**	**Mar 2025**	**Dec 2024**
Share price ($/common share)								
High	77.02	75.70	66.66	73.80	66.06	57.92	64.95	68.73
Low	57.93	61.74	56.48	58.23	54.03	41.87	44.68	49.20
Close	61.30	73.91	65.89	58.55	65.35	54.80	47.83	63.72
Volume of shares traded (millions)	39.0	36.2	49.3	50.4	43.8	48.7	59.2	38.0

Outstanding share and partnership unit data

At October 28, 2026, the Company had 157.488 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), and 8 million Cumulative Rate Reset Preference Shares (Series 5) outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares at October 28, 2026 were 158.750 million. On February 23, 2026, the Company retired its special limited voting shares and entered into a 10-year agreement with the City of Edmonton which includes obligations regarding the head office and a commitment to maintain a corporate community giving program, or similar program benefiting the Edmonton area, of not less than $1 million per calendar year. These transactions occurred in exchange for cash consideration totaling $75 million, comprised of $40 million paid in the first quarter of 2026 and $35 million payable in 2027, which were recorded in accumulated deficit.

At October 28, 2026, CPLP had 349.092 million general partnership units outstanding and 1,299.228 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)

Nine months ended September 30, 2026 and 2025

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2026 and 2025

Condensed Interim Consolidated Financial Statements:

Condensed Interim Consolidated Statements of Income	41
Condensed Interim Consolidated Statements of Comprehensive Income	42
Condensed Interim Consolidated Statements of Financial Position	43
Condensed Interim Consolidated Statements of Changes in Equity	44
Condensed Interim Consolidated Statements of Cash Flows	46
Notes to the Condensed Interim Consolidated Financial Statements	47

CAPITAL POWER CORPORATION

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

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Revenues	$ 806	$ 1,197	$ 2,698	$ 2,559
Other income	25	16	78	83
Energy purchases and fuel	(311)	(632)	(1,369)	(1,381)
Gross margin	520	581	1,407	1,261
Other raw materials and operating charges	(27)	(55)	(176)	(161)
Staff costs and employee benefits expense	(43)	(48)	(150)	(142)
Depreciation and amortization	(207)	(157)	(555)	(421)
Other administrative expense	(53)	(54)	(174)	(188)
Foreign exchange gain (loss)	2	(7)	(20)	16
Operating income	192	260	332	365
Net finance expense (note 4)	(95)	(92)	(282)	(217)
Income from equity-accounted investments	24	25	21	65
Loss on disposals and other transactions	(17)	(5)	(17)	(12)
Income before tax	104	188	54	201
Income tax expense (note 5)	(37)	(35)	(15)	(29)
Net income	$ 67	$ 153	$ 39	$ 172
Attributable to:				
Non-controlling interests	$ —	$ (1)	$ 1	$ (1)
Shareholders of the Company	$ 67	$ 154	$ 38	$ 173
Earnings per share attributable to shareholders of the Company:				
Basic (note 6)	$ 0.37	$ 0.94	$ 0.09	$ 1.02
Diluted (note 6)	$ 0.37	$ 0.94	$ 0.09	$ 1.01

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Net income	$ 67	$ 153	$ 39	$ 172
Other comprehensive income (loss):				
Items that may be reclassified subsequently to net income:				
Unrealized gain on derivative instruments[1] (note 7)	25	1	63	7
Reclassification of gains on derivative instruments to net income[2] (note 7)	(13)	(5)	(44)	(23)
Equity-accounted investments[3]	5	(1)	8	(7)
Exchange gains (losses) on translation of foreign operations	4	78	143	(97)
Net investment hedge - net loss[4] (note 7)	—	—	(8)	—
Other comprehensive income (loss) for the period, net of tax	21	73	162	(120)
Total comprehensive income	$ 88	$ 226	$ 201	$ 52
Attributable to:				
Non-controlling interests	$ —	$ (1)	$ 1	$ (1)
Shareholders of the Company	$ 88	$ 227	$ 200	$ 53

1 For the three and nine months ended September 30, 2026, net of income tax expense of $8 and $19, respectively. For the three and nine months ended September 30, 2025, net of income tax expense of $1 and $4, respectively.
2 For the three and nine months ended September 30, 2026, net of reclassification of income tax expense of $5 and $14, respectively. For the three and nine months ended September 30, 2025, net of reclassification of income tax expense of $2 and $7, respectively.
3 For the three and nine months ended September 30, 2026, net of income tax expense of $3 and $4, respectively. For the three and nine months ended September 30, 2025, net of income tax recovery of $1 and $3, respectively.
4 For the three and nine months ended September 30, 2026, net of income tax recovery of nil and $1, respectively.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

		September 30, 2026		December 31, 2025
Assets				
Current assets:				
Cash and cash equivalents	$	150	$	119
Trade and other receivables		697		569
Income taxes recoverable		102		216
Inventories		279		323
Derivative financial instruments (note 7)		329		315
		1,557		1,542
Non-current assets:				
Property, plant and equipment		11,485		11,253
Equity-accounted investments		1,048		1,064
Intangible assets and goodwill		589		620
Right-of-use assets (note 8)		145		136
Derivative financial instruments (note 7)		314		373
Government grants receivable		137		320
Deferred tax assets		55		26
Other assets		111		107
Total assets	$	15,441	$	15,441
Liabilities and equity				
Current liabilities:				
Trade and other payables	$	798	$	789
Derivative financial instruments (note 7)		451		274
Loans and borrowings (note 9)		482		347
Provisions		102		112
Deferred revenue and other liabilities		88		113
		1,921		1,635
Non-current liabilities:				
Derivative financial instruments (note 7)		723		719
Loans and borrowings (note 9)		6,323		6,383
Lease liabilities		168		154
Deferred tax liabilities		876		904
Provisions		434		504
Deferred revenue and other liabilities		265		293
Total liabilities	$	10,710	$	10,592
Share capital (note 10)		5,127		5,036
Deficit		(721)		(349)
Other reserves		332		170
Equity attributable to shareholders of the Company	$	4,738	$	4,857
Non-controlling interests		(7)		(8)
Total equity		4,731		4,849
Total liabilities and equity	$	15,441	$	15,441

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 10)	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, 2026	$ 5,036	$ 78	$ 91	$ (9)	$ 10	$ (349)	$ 4,857	$ (8)	$ 4,849
Net income	—	—	—	—	—	38	38	1	39
Other comprehensive income	—	27	135	—	—	—	162	—	162
Total comprehensive income	—	27	135	—	—	38	200	1	201
Issue of share capital, net	12	—	—	—	—	—	12	—	12
Repurchase of special limited voting shares[2] (note 10)	—	—	—	—	—	(58)	(58)	—	(58)
Common share dividends (note 10)	—	—	—	—	—	(328)	(328)	—	(328)
Preferred share dividends, net of tax[3] (note 10)	—	—	—	—	—	(24)	(24)	—	(24)
Dividends reinvested	79	—	—	—	—	—	79	—	79
Balance, September 30, 2026	$ 5,127	$ 105	$ 226	$ (9)	$ 10	$ (721)	$ 4,738	$ (7)	$ 4,731

[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 tax recovery of $17.
[3] Including income tax expense of $2.

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 10)	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	—	—	—	—	—	173	173	(1)	172
Other comprehensive loss	—	(23)	(97)	—	—	—	(120)	—	(120)
Total comprehensive (loss) income	—	(23)	(97)	—	—	173	53	(1)	52
Issue of share capital, net[2]	653	—	—	—	—	—	653	—	653
Common share dividends (note 10)	—	—	—	—	—	(299)	(299)	—	(299)
Preferred share dividends, net of tax[3] (note 10)	—	—	—	—	—	(22)	(22)	—	(22)
Dividends reinvested	55	—	—	—	—	—	55	—	55
Distributions to non-controlling interests	—	—	—	—	—	—	—	(2)	(2)
Balance, September 30, 2025	$ 5,009	$ 85	$ 143	$ (9)	$ 10	$ (222)	$ 5,016	$ (8)	$ 5,008

[1] Accumulated other comprehensive income. 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 $29, income tax recovery of $7, and share options exercised of $8.
[3] Net of income tax expense of $2.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Nine months ended September 30,	
	2026	2025
Cash flows from operating activities:		
Net income	$ 39	$ 172
Non-cash adjustments:		
Depreciation and amortization	555	421
Net finance expense	282	217
Fair value changes on commodity derivative instruments and emission credits held for trading	238	176
Unrealized foreign exchange losses (gains)	16	(16)
Income tax expense	15	29
Income from equity-accounted investments	(21)	(65)
Tax equity attributes	(61)	(55)
Other	1	26
Change in fair value of derivative instruments, cash settlement	(10)	(7)
Distributions received from equity-accounted investments	72	47
Interest paid	(254)	(202)
Income taxes recovered	12	14
Other	(16)	(23)
Change in non-cash operating working capital	39	23
Net cash flows from operating activities	907	757
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets, net[1]	(642)	(576)
Business acquisition, net of acquired cash	—	(2,974)
Government grants received	50	60
Other	5	13
Net cash flows used in investing activities	(587)	(3,477)
Cash flows (used in) from financing activities:		
Net proceeds from issue of loans and borrowings[2]	297	1,809
Repayment of loans and borrowings (note 9)	(268)	(78)
Capitalized interest paid	(22)	(31)
Issue of share capital[3]	12	646
Dividends paid (note 10)	(267)	(248)
Income taxes paid on preferred share dividends	—	(8)
Repurchase of special limited voting shares (note 10)	(40)	—
Distributions to non-controlling interests	—	(2)
Other	(5)	(6)
Net cash flows (used in) from financing activities	(293)	2,082
Foreign exchange gain (loss) on cash held in foreign currency	4	(23)
Net increase (decrease) in cash and cash equivalents	31	(661)
Cash and cash equivalents, beginning of period	119	865
Cash and cash equivalents, end of period	$ 150	$ 204

[1] Reflects total additions, increased by $95 for changes in non-cash investing working capital and other non-current liabilities (2025 – increased by $117).
[2] Net of deferred debt issue costs of $8 (2025 - $15).
[3] Net of share issue costs of nil (2025 - $29).

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 2025 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 2025 annual consolidated financial statements, except as described in note 3.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 30, 2026.

3. Changes to accounting policies

Current accounting changes:

The following amendments to IFRS Accounting Standards became effective on January 1, 2026 and were adopted by the Company:

- *Contracts Referencing Nature-dependent Electricity - Amendment to IFRS 9 and IFRS 7*

  In December 2024, the IASB issued targeted amendments to IFRS 9 *Financial Instruments* (IFRS 9) and IFRS 7 *Financial Instruments: Disclosures* (IFRS 7). The targeted amendments aimed to help companies better report the financial effects of nature-dependent electricity contracts, which are often structured as power purchase agreements (PPAs) or virtual PPAs. The amendments included clarifying the application of the ‘own-use’ requirements; permitting hedge accounting if these contracts are used as hedging instruments; and adding new disclosure requirements. The amendments did not have a material impact on the Company's consolidated financial statements.

- *Amendments to the Classification and Measurement of Financial Instruments - Amendments to IFRS 9 and IFRS 7*

  In May 2024, the IASB issued targeted amendments to IFRS 9 and IFRS 7 that clarified the timing of recognition and derecognition of financial assets and liabilities, and introduced a derecognition exception for financial liabilities settled through electronic payment systems, when certain criteria are met. The amendments also clarified the application of the solely payments of principal and interest (SPPI) criterion and added new disclosures for financial instruments with contractual terms that can change the cash flows. Adopting the amendments resulted in a change in the accounting policy for derecognizing trade and other payables. The amendments did not have a material impact on the Company's consolidated financial statements and the Company was not required to restate prior periods to reflect the amendments under their transitional provisions.

3. Changes to accounting policies, continued

Future accounting changes:

- *IFRS 18 Presentation and Disclosure in the Financial Statements*

  In April 2024, the IASB issued IFRS 18 *Presentation and Disclosure in the Financial Statements*, which replaces IAS 1 *Presentation of Financial Statements* and is effective for annual reporting periods beginning on or after January 1, 2027, with early application permitted. IFRS 18 introduces new presentation and disclosure requirements, including mandatory subtotals for operating profit and profit before financing and income taxes, and prescribed categories for the classification of income and expenses. Management is currently assessing any changes that may be necessary to financial reporting systems, processes, and controls arising from the adoption of IFRS 18.

4. Net finance expense

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Interest expense				
Interest on loans and borrowings	$ 94	$ 93	$ 281	$ 239
Capitalized interest	(8)	(10)	(22)	(31)
Total interest expense	86	83	259	208
Other finance expense (income)				
Accretion on decommissioning provisions	5	4	13	9
Interest on lease liabilities	2	2	8	8
Interest on government grants receivable	(2)	(2)	(5)	(6)
Other	4	5	7	(2)
Net finance expense	$ 95	$ 92	$ 282	$ 217

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 September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Net income before tax	$ 104	$ 188	$ 54	$ 201
Income tax at the statutory rate of 23%	24	43	12	46
Increase (decrease) resulting from:				
Non-deductible expenses and non-taxable income	—	4	5	—
Amounts attributable to non-controlling interests, equity-accounted investments, and tax equity interests	(5)	(7)	(15)	(14)
Change in unrecognized tax benefits	9	—	9	—
Statutory and other rate differences	13	5	8	2
Other	(4)	(10)	(4)	(5)
Income tax expense	$ 37	$ 35	$ 15	$ 29

6. Earnings per share

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

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Earnings for the period attributable to shareholders	$ 67	$ 154	$ 38	$ 173
Preferred share dividends[1]	(8)	(8)	(24)	(22)
Earnings available to common shareholders	$ 59	$ 146	$ 14	$ 151
Weighted average number of common shares	157,351,309	155,349,949	156,830,387	148,642,287
Basic earnings per share	$ 0.37	$ 0.94	$ 0.09	$ 1.02
Effect of dilutive share purchase options	306,531	424,617	341,636	346,508
Diluted weighted average number of common shares	157,657,840	155,774,566	157,172,023	148,988,795
Diluted earnings per share	$ 0.37	$ 0.94	$ 0.09	$ 1.01

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

7. Derivative financial instruments and hedge accounting

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

The Company has elected to apply hedge accounting to certain derivatives used to manage commodity price risk relating to electricity prices in Alberta, interest rate risk relating to future borrowings, and foreign exchange risk relating to future capital investment in U.S. dollars.

During the second quarter of 2026, the Company designated the foreign currency risk component of the $213 million (US$150 million) private placement debt issued by CPC at 3.24%, due October 29, 2033, as a net investment hedge of its U.S. operations, at a hedge ratio of 1:1. As such, the effective portion of foreign exchange gains and losses on the debt, included in loans and borrowings, is recognized in other comprehensive income.

7. Derivative financial instruments and hedge accounting, continued

	September 30, 2026						
	Energy and emission allowances		Interest rate		Foreign exchange		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:							
Current	$ 24	$ 305	$ —	$ —	$ —	$ —	$ 329
Non-current	10	278	24	2	—	—	314
Derivative instruments liabilities:							
Current	(1)	(437)	—	—	—	(13)	(451)
Non-current	(1)	(720)	—	—	—	(2)	(723)
Net fair value	$ 32	$ (574)	$ 24	$ 2	$ —	$ (15)	$ (531)
Net notional buys (sells) (millions):							
Megawatt hours of electricity	(2)	(64)					
Gigajoules of natural gas purchased		408					
Gigajoules of natural gas basis swaps		30					
Metric tonnes of emission allowances		25					
Number of renewable energy credits		(7)					
Interest rate swaps			$ 564	$ 68			
Forward currency buys (U.S. dollars)					$ —	$ (346)	
Range of remaining contract terms (years)	0.1 to 3.0	0.1 to 20.0	0.3 to 2.0	1.8 to 2.3	—	0.1 to 1.3	

	December 31, 2025						
	Energy and emission allowances		Interest rate		Foreign exchange		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:							
Current	$ 18	$ 296	$ —	$ —	$ —	$ 1	$ 315
Non-current	11	358	4	—	—	—	373
Derivative instruments liabilities:							
Current	(1)	(272)	(1)	—	—	—	(274)
Non-current	(10)	(708)	(1)	—	—	—	(719)
Net fair value	$ 18	$ (326)	$ 2	$ —	$ —	$ 1	$ (305)
Net notional buys (sells) (millions):							
Megawatt hours of electricity	(4)	(73)					
Gigajoules of natural gas purchased		533					
Gigajoules of natural gas basis swaps		51					
Metric tonnes of emission allowances		6					
Number of renewable energy credits		(9)					
Interest rate swaps			$ 1,074	$ 113			
Forward currency buys (U.S. dollars)					$ 10	$ (111)	
Range of remaining contract terms (years)	0.1 to 4.0	0.1 to 21.0	0.2 to 2.7	0.2 to 2.5	0.1	0.1 to 0.4	

7. Derivative financial instruments and hedge accounting, continued

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

	Three months ended September 30, 2026		Three months ended September 30, 2025	
	Unrealized (losses) gains	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (9)	$ 16	$ —	$ 6
Energy and emission allowances non-hedges	(86)	6	3	68
Interest rate cash flow hedges	24	2	(6)	4
Interest rate non-hedges	2	—	(1)	—
Foreign exchange cash flow hedges	—	—	1	(3)
Foreign exchange non-hedges	3	(3)	—	11

	Nine months ended September 30, 2026		Nine months ended September 30, 2025	
	Unrealized (losses) gains	Realized gains (losses)	Unrealized (losses) gains	Realized gains (losses)
Energy cash flow hedges	$ (1)	$ 52	$ (18)	$ 23
Energy and emission allowances non-hedges	(224)	77	(169)	183
Interest rate cash flow hedges	25	6	4	10
Interest rate non-hedges	2	4	(1)	—
Foreign exchange cash flow hedges	—	—	(5)	(3)
Foreign exchange non-hedges	(16)	(4)	—	—

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

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
Revenues	$ (166)	$ 311	$ (16)	$ 300
Energy purchases and fuel	102	(234)	(79)	(263)
Foreign exchange gain (loss)	—	8	(20)	(3)
Net finance expense	4	3	12	9

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

	September 30, 2026
Within one year	$ 35
Between one and five years	58
After five years	19
	$ 112

8. Leases

In January 2026, the Company extended its Arlington Valley tolling agreement by 7 years, from 2031 to 2038, which included a commitment to add 35 MW of incremental capacity. Consistent with its previous classification, the contract has been assessed as an operating lease.

The minimum undiscounted future lease payments to be received are:

2026	$	11
2027		77
2028		79
2029		80
2030		82
Thereafter		1,124
Total	$	1,453

9. Loans and borrowings

During 2026, the Company repaid $91 million (US$65 million) of Capital Power L.P (CPLP) unsecured senior notes bearing an effective interest rate of 5.67% and $160 million of CPC private placement debt bearing an effective interest rate of 3.85%.

In June 2026, the Company extended its $1.5 billion committed revolving credit facility to 2031 and its $600 million committed revolving credit facility to 2028.

Tax equity financing

Capital Power's Hornet Solar and Bear Branch Solar projects reached mechanical completion on July 10, 2026, and September 16, 2026, respectively. The Company received approximately $26 million (US$18 million) for Hornet Solar and $9 million (US$7 million) for Bear Branch Solar in tax equity financing, net of issue costs of $6 million (US$4 million) associated with the financings in exchange for Class A interests in project subsidiaries.

Tax equity financing represents the contribution made by the project investor, adjusted for earnings, tax benefits and cash distributions realized/paid over time. The maturity dates of these obligations are subject to change and are driven by the dates on which the project investor reaches the agreed upon target rate of return. In accordance with the Company's material accounting policies (as described in the 2025 annual consolidated financial statements), the amounts paid by the project investors for their equity stakes are classified as loans and borrowings on the consolidated statements of financial position until the projects have yielded an agreed-upon target rate of return to the project investors.

10. Share capital

On February 23, 2026, the Company retired its special limited voting shares and entered into a 10-year agreement with the City of Edmonton which includes obligations regarding the head office and a commitment to maintain a corporate community giving program, or similar program benefitting the Edmonton area, of not less than $1 million per calendar year. These transactions occurred in exchange for cash consideration totaling $75 million, comprised of $40 million paid in the first quarter of 2026 and $35 million payable in 2027, which were recorded in retained earnings.

On July 28, 2026, the Company's Board of Directors approved an increase of 2% in the annual dividend for holders of its common shares, from $0.6910 per common share to $0.7048 per common share. This increased common share dividend will commence with the third quarter 2026 quarterly dividend payment on October 30, 2026 to shareholders of record at the close of business on September 29, 2026.

10. Share capital, continued

Common and preferred share dividends

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2026		2025		2026		2025	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.7048	$ 111	$ 0.6910	$ 107	$ 2.0868	$ 328	$ 1.9948	$ 299
Preference:								
Series 1[1]	0.3099	1	0.1638	1	0.9297	4	0.4914	3
Series 3	0.4288	3	0.4288	3	1.2863	8	1.2863	8
Series 5	0.4144	3	0.4144	3	1.2433	10	1.2433	9

	Dividends paid[2]							
	For the three months ended September 30,				For the nine months ended September 30,			
	2026		2025		2026		2025	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[3]	$ 0.6910	$ 108	$ 0.6519	$ 101	$ 2.0730	$ 324	$ 1.9557	$ 283

1 Effective December 31, 2025, the annual fixed dividend rate for the next five-year period has been reset to 4.958% from 2.621%.
2 Preference share dividends are declared and paid in the same period.
3 For the nine months ended September 30, 2026 common dividends consist of $245 million paid in cash and $79 million through the Company's dividend re-investment plan (nine months ended September 30, 2025, $228 million paid in cash and $55 million through the Company's dividend re-investment plan).

11. 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:

		September 30, 2026		December 31, 2025	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets[1]					
Government grants receivable[2]	Level 2	$ 360	$ 348	$ 406	$ 389
Financial liabilities[1]					
Loans and borrowings	Level 2	$ 6,805	$ 6,926	$ 6,730	$ 7,052

1 Includes current portion.
2 Government grants receivable includes investment tax credits receivable of $174 million, recorded in trade and other receivables, and $186 million related to off-coal compensation from the Government of Alberta (GoA), as described in the Company's 2025 annual consolidated financial statements.

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.

11. Financial instruments, continued

Fair value measurements are categorized into levels based upon the lowest level of significant input, as described in the Company's 2025 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.

	September 30, 2026			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ —	$ 580	$ 63	$ 643
Derivative financial instruments liabilities	—	(865)	(309)	(1,174)

	December 31, 2025			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ —	$ 618	$ 70	$ 688
Derivative financial instruments liabilities	—	(655)	(338)	(993)

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2025 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:

	September 30, 2026	December 31, 2025
REC pricing (per certificate) – Solar	$2 to $26	$3 to $25
REC pricing (per certificate) – Wind	$2 to $5	$3 to $5
Forward power pricing (per MWh) – Solar	$22 to $229	$21 to $179
Forward power pricing (per MWh) – Wind	$16 to $119	$18 to $101
Average monthly notional generation (MWh) – Solar	5,664 to 12,080	6,537 to 13,018
Average monthly notional generation (MWh) – Wind	17,715 to 49,178	17,703 to 59,308

11. Financial instruments, continued

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

	September 30, 2026	December 31, 2025
REC pricing – Solar	$ 3	$ 3
REC pricing – Wind	$ 1	$ 2
Forward power pricing – Solar	$ 17	$ 22
Forward power pricing – Wind	$ 40	$ 42
Generation – Solar	$ 5	$ 7
Generation – Wind	$ 5	$ 11

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:

	September 30, 2026	December 31, 2025
At January 1[1]	$ (268)	$ (156)
Additions	—	(12)
Unrealized and realized [2]	—	(153)
Settlements	31	44
Transfers[3]	—	(1)
Foreign exchange (losses) gains	(9)	10
At end of period	$ (246)	$ (268)

[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.

12. Segment information

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.

12. Segment information, continued

The following tables provide each reportable segment's results in the format that the Company's Chief Operating Decision Maker (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 equity-accounted investments, 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 September 30, 2026								
	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	$ 525	$ 42	$ 353	$ 45	$ —	$ 965	$ (134)	$ —	$ 831
Energy purchases and fuel	(289)	(1)	(76)	2	—	(364)	53	—	(311)
Other raw materials and operating charges	(1)	(8)	(14)	(5)	(1)	(29)	2	—	(27)
Staff costs and employee benefits expense	(12)	(1)	(10)	(1)	(22)	(46)	3	—	(43)
Other administrative expense	(17)	(6)	(13)	(5)	(19)	(60)	7	—	(53)
Remove unrealized changes in fair value of commodity derivatives	(1)	(5)	116	(21)	—	89	—	(89)	—
Remove other non-recurring items	3	—	(5)	—	—	(2)	—	2	—
Adjusted EBITDA[2]	208	21	351	15	(42)	553			
Depreciation and amortization									(207)
Foreign exchange gain									2
Loss on disposals and other transactions									(17)
Net finance expense									(95)
Income from equity-accounted investments									24
Income before tax									$ 104

	Three months ended September 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	$ 538	$ 18	$ 778	$ 9	$ 5	$ 1,348	$ (135)	$ —	$ 1,213
Energy purchases and fuel	(327)	(2)	(354)	(3)	—	(686)	54	—	(632)
Other raw materials and operating charges	(20)	(6)	(32)	(5)	(1)	(64)	9	—	(55)
Staff costs and employee benefits expense	(10)	—	(8)	(1)	(33)	(52)	4	—	(48)
Other administrative expense	(14)	(5)	(18)	(4)	(19)	(60)	6	—	(54)
Remove unrealized changes in fair value of commodity derivatives	14	13	(59)	19	—	(13)	—	13	—
Remove other non-recurring items	—	—	—	—	4	4	—	(4)	—
Adjusted EBITDA[2]	181	18	307	15	(44)	477			
Depreciation and amortization									(157)
Foreign exchange loss									(7)
Loss on disposals and other transactions									(5)
Net finance expense									(92)
Income from equity-accounted investments									25
Income before tax									$ 188

12. Segment information, continued

	Nine months ended September 30, 2026								
	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	$ 1,633	$ 155	$ 1,275	$ 118	$ 13	$ 3,194	$ (418)	$ —	$ 2,776
Energy purchases and fuel	(882)	(4)	(671)	3	—	(1,554)	185	—	(1,369)
Other raw materials and operating charges	(58)	(21)	(113)	(15)	(7)	(214)	38	—	(176)
Staff costs and employee benefits expense	(34)	(2)	(32)	(3)	(90)	(161)	11	—	(150)
Other administrative expense	(45)	(15)	(55)	(17)	(63)	(195)	21	—	(174)
Remove unrealized changes in fair value of commodity derivatives	(52)	(33)	340	(17)	—	238	—	(238)	—
Remove other non-recurring items	5	—	(5)	—	—	—	—	—	—
Adjusted EBITDA[2]	567	80	739	69	(147)	1,308			
Depreciation and amortization									(555)
Foreign exchange loss									(20)
Loss on disposals and other transactions									(17)
Net finance expense									(282)
Income from equity-accounted investments									21
Income before tax									$ 54

	Nine months ended September 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	$ 1,517	$ 76	$ 1,294	$ 124	$ 36	$ 3,047	$ (405)	$ —	$ 2,642
Energy purchases and fuel	(911)	(5)	(638)	3	—	(1,551)	170	—	(1,381)
Other raw materials and operating charges	(61)	(18)	(89)	(14)	(5)	(187)	26	—	(161)
Staff costs and employee benefits expense	(37)	(2)	(27)	(2)	(86)	(154)	12	—	(142)
Other administrative expense	(43)	(13)	(47)	(15)	(92)	(210)	22	—	(188)
Remove unrealized changes in fair value of commodity derivatives	85	40	74	(23)	—	176	—	(176)	—
Remove other non-recurring items	4	—	—	—	41	45	—	(45)	—
Adjusted EBITDA[2]	554	78	567	73	(106)	1,166			
Depreciation and amortization									(421)
Foreign exchange gain									16
Loss on disposals and other transactions									(12)
Net finance expense									(217)
Income from equity-accounted investments									65
Income before tax									$ 201

[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, 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.

12. Segment information, continued

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 September 30, 2026			At December 31, 2025		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 5,486	$ 5,999	$ 11,485	$ 5,592	$ 5,661	$ 11,253
Equity-accounted investments	342	706	1,048	397	667	1,064
Intangible assets and goodwill	409	180	589	428	192	620
Right-of-use assets	53	92	145	50	86	136
Other assets[3]	48	67	115	59	61	120
	$ 6,338	$ 7,044	$ 13,382	$ 6,526	$ 6,667	$ 13,193

[3] Includes current and non-current portions of finance lease receivables.

Major customers

For the three and nine months ended September 30, 2026, the Company recorded revenues of $134 and $338 million, respectively, from the Alberta Electric System Operator (three and nine months ended September 30, 2025 - $180 million and $461 million), and $148 million and $455 million, respectively, from the Ontario Independent Electricity System Operator (three and nine months ended September 30, 2025 - $110 million and $345 million), within the Canada flexible generation and Canada renewables segments, and $305 million and $894 million, respectively, from PJM, within the U.S. flexible generation segment (three and nine months ended September 30, 2025 - $210 million and $265 million). 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 September 30, 2026						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 419	$ 18	$ 408	$ 17	$ 862	$ (103)	$ 759
Emission credit revenues	—	11	—	1	12	35	47
Total revenues[4]	$ 419	$ 29	$ 408	$ 18	$ 874	$ (68)	$ 806

	Three months ended September 30, 2025						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 454	$ 19	$ 351	$ 13	$ 837	$ 350	$ 1,187
Emission credit revenues	—	10	—	1	11	(1)	10
Total revenues[4]	$ 454	$ 29	$ 351	$ 14	$ 848	$ 349	$ 1,197

12. Segment information, continued

	Nine months ended September 30, 2026						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,202	$ 51	$ 1,124	$ 51	$ 2,428	$ 196	$ 2,624
Emission credit revenues	—	40	—	3	43	31	74
Total revenues[4]	$ 1,202	$ 91	$ 1,124	$ 54	$ 2,471	$ 227	$ 2,698

	Nine months ended September 30, 2025						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,293	$ 58	$ 652	$ 48	$ 2,051	$ 465	$ 2,516
Emission credit revenues	—	35	—	3	38	5	43
Total revenues[4]	$ 1,293	$ 93	$ 652	$ 51	$ 2,089	$ 470	$ 2,559

[4] Included within trade and other receivables at September 30, 2026, were amounts related to contracts with customers of $265 million (2025 - $321 million).