2025 Integrated Annual Report

Capital Power

Contents

About this report

Our Integrated Annual Report (IAR) aligns our financial and environmental, social, and governance (ESG) reporting and provides our stakeholders with a comprehensive view of our priorities, performance, and strategy for long-term success. Elements of the conventional management's discussion and analysis (MD&A), including the overview of our business and corporate structure, corporate strategy, and outlook and targets for 2026, are integrated into the Introduction and other sections of this report. Other MD&A reporting requirements are incorporated within the Business report section. Information about Capital Power's Non-GAAP financial measures and ratios can be found in the Business report section.

This report provides an overview of our performance from January 1, 2025, through December 31, 2025, and includes a summary of our management approach and highlights material topics within our business. Information throughout the report is disclosed in alignment with the recommendations of the Task Force on Climate-related Financial Disclosure (TCFD) framework, including details about Capital Power's climate change governance, strategy, risk management, metrics, and targets. It also includes a Sustainability Accounting Standards Board (SASB) standards index that addresses relevant metrics related to the Electric Utilities and Power Generators sector standards. TCFD and SASB are now part of the IFRS Foundation. All dollar figures are in Canadian dollars.

In accordance with its terms of reference, the Audit Committee of our Board of Directors (the Board) reviews the contents of the IAR and recommends its approval by the Board. The Board approved this IAR on March 3, 2026.

GHD Limited assurance

Capital Power engaged GHD Limited to provide independent limited assurance on select performance information within this report. The symbol ☑ indicates metrics that have been assured for 2025. GHD Limited's assurance report is on pages 72-78. Details on the boundaries of our sustainability reporting and definitions of assured sustainability performance indicators can be found in the Sustainability appendix, starting on page 156.

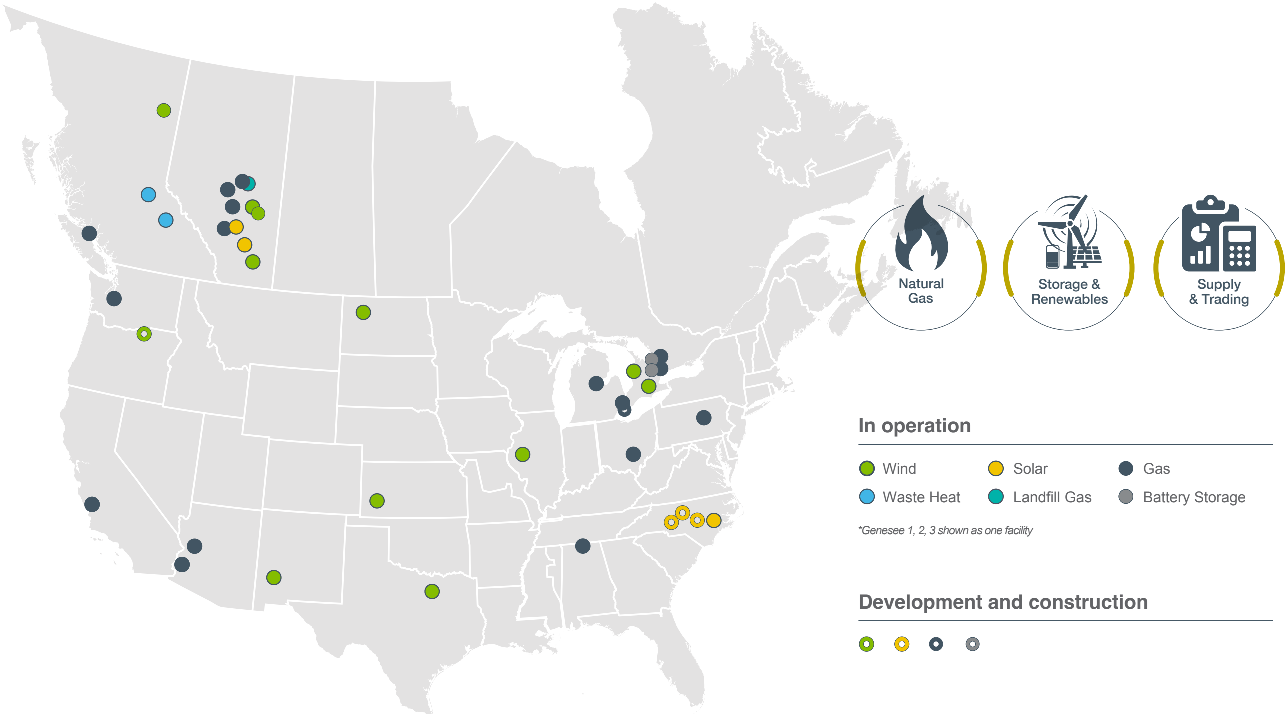
Territorial acknowledgement

In the spirit of reconciliation, Capital Power respectfully acknowledges that we operate within the ancestral homelands, traditional and treaty territories of the Indigenous Peoples of Turtle Island, (North America). Our head office is located within the traditional and contemporary home of many Indigenous Peoples of the Treaty 6 Territory and Métis Homeland. We acknowledge the diverse Indigenous communities that are located in these areas and whose presence continues to enrich the community.

About us

Powering Change by Changing Power™

Capital Power[1] (TSX: CPX) 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 deep expertise and an investment-grade credit rating, we provide safe, reliable power communities can depend on. We are Powering Change by Changing Power™.



Scale[2]

~$16B
Enterprise value

~$10B
Market capitalization

Investment Grade BBB-/BBB (low)[3]

Stability[2]

~90%
A-rated PPA Counterparties[3]

~75%
Long-Term Contracted Adj. EBITDA[4]

High Quality Cash Flows

Cumulative Growth and Capacity[2]

~$8.5B
Invested (M&A)

12GW
~90% Natural Gas / ~60% U.S.

Diverse fleet across 5 key North American markets

1. 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. In this report, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicated, means Capital Power Corporation together with its subsidiaries.
2. As of December 31, 2025
3. Investment Grade Credit Ratings – S&P (BBB-), DBRS (BBB low) and Fitch (BBB-)
4. Adjusted EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures and Ratios

Board Chair and CEO letter

Delivering growth and value in a transforming energy market

A message from

Jill Gardiner,
Board Chair,

and **Avik Dey**,
President and CEO

The past year marked a pivotal chapter for Capital Power as the company advanced its position as North America's most compelling energy infrastructure investment opportunity, built to lead the energy expansion. With a portfolio defined by scale, diversification, and unmatched operational and commercial excellence, we are exceptionally well positioned to meet the accelerating demand for reliable, affordable power. Our fleet is not only capable of growth; it is engineered for it.

A growth era for power has arrived – and natural gas is critical to meet this demand.

Power demand is increasing at an unprecedented pace, reshaping the electricity sector, creating a long-term opportunity. This growth is driven by industrial reshoring, electrification, and the rapid expansion of AI-enabled technologies. As power grids integrate more renewable generation, storage, and emerging technologies, reliability remains paramount and natural gas remains the backbone of the system, providing essential dispatchable capacity, balancing variability, and supporting baseload demand. Quite simply, there is no scalable substitute capable of meeting these requirements with the same cost, efficiency and speed. Natural gas is the lowest cost and fastest-to-market solution to reliably power the North American economy today and for decades to come.

In 2025, we delivered on our commitments.

In 2025, we made significant progress toward the key goals we set, strengthening our growth platform and transforming our company.

Our over 700 employees delivered 45 TWh of safe, reliable power from 35 operating facilities across 14 states and 3 provinces – operating with the discipline and focus that defines who we are as a company.

We achieved strong financial performance across our diversified portfolio, and a 10-year annualized shareholder return of approximately 20%, including our 12th consecutive annual dividend increase.

We achieved a critical milestone, with the largest acquisition in our history, adding 2.2 GW of flexible generation through the Hummel Station and Rolling Hills facilities and expanding into North America's largest and most liquid power market, PJM.

In addition to expanding our natural gas portfolio, we delivered our first battery storage projects – the 120-MW York battery energy storage system (BESS) and 50-MW Goreway BESS. These long-term contracted assets will generate approximately $35 million in annual EBITDA for more than 20 years and further position Capital Power as a leader in Ontario's rapidly expanding storage market.

Board Chair and CEO letter

Complementing this, we secured an improved long-term contract at Midland Cogeneration Venture (MCV) extending to 2040, with 10 years of incremental revenue, and progressed plans for a potential data centre development adjacent to the facility. This agreement demonstrates our ability to partner with strong investment grade utilities, as well as our commitment to long-term value creation and stability for both our stakeholders and our counterparties.

These weren't just transactions – they represented our team's ability to identify, execute, and integrate complex assets in North America's most competitive power market. The successful closing and integration of our PJM acquisitions demonstrates the company's ability to execute in complex environments while maintaining operational excellence across the entire portfolio.

Our renewable energy efforts also continued to advance with construction of the Hornet Solar project in North Carolina and ongoing development of Maple Leaf Solar and Bear Branch Solar, which together will add 180 MW of renewable generation. We also commissioned our 122 MW Halkirk 2 Wind facility in December in Alberta.

Throughout these achievements, we remained committed to the communities where we operate. In 2025, we contributed $3.7 million to charitable organizations across our office and operational communities, reflecting our belief in responsible growth and stewardship of thriving communities and opportunities for the next generations to come.

Strong governance and leadership remain at the core of our success.

Our Board of Directors provides independent, effective oversight and guidance, ensuring alignment with our purpose: *Powering Change by Changing Power™*. We are grateful for their steadfast leadership and focus on sustainable, long-term value creation.

Equally critical is the dedication of our Executive Team and employees. With over 700 employees, we are one of only a few platforms in North America that has the in-house capabilities to operate, commercialize, and trade megawatts on both sides of the U.S.-Canada border.

This year, we announced the planned retirements of two leaders whose contributions have left a lasting mark on Capital Power: Sandra Haskins, Senior Vice President, Finance & Chief Financial Officer, following 23 years of exceptional service, and Jacquie Pylypiuk, Senior Vice President, Technology & Chief People and Culture Officer, after nearly 14 years of dedicated service. Sandra's leadership has been integral to strengthening our strategy, culture, and financial resilience, while Jacquie has played a pivotal role in shaping our industry-leading culture. We are deeply grateful for their enduring impact and the legacy they leave behind.

Looking ahead to 2026

Capital Power has strong momentum and multiple pathways for value creation, including optimizing and re-contracting our existing fleet, expanding natural gas generation, pursuing accretive acquisitions, and further developing renewables and storage. We remain focused on cash flow per share growth, strategic capital allocation, and maintaining our investment-grade credit rating, while targeting an average annual total shareholder return of 13–15%.

Our scale, diversification, and commercial expertise position us to meet rising demand for reliable, flexible power, supporting growth without compromising stability or adding excess leverage. With up to 8 GW of growth opportunities in our existing fleet (through upgrades and expansions) and more than 17 GW in our merger and acquisition and development pipeline, we are confident in our ability to deliver durable performance and top-tier shareholder value while preserving grid reliability and affordability.

As we look ahead to 2026, operational excellence remains a defining strength for Capital Power. This disciplined, ownership-driven approach ensures we maintain the highest standards in safety and reliability while continually improving output, environmental performance, reducing downtime, and optimizing resource use. Together, these capabilities position us to generate sustained value and support our growth ambitions with a resilient, high-performing fleet throughout 2026.

A final word of thanks

We extend our sincere gratitude to our employees for their commitment to excellence, to our Board for their leadership, and to our communities, partners, and shareholders for their continued support. Capital Power is entering a defining period of growth, and together we are building the reliable, affordable and lower-carbon power system that North America's future demands.

Sincerely,

Jill Gardiner
Board Chair

Avik Dey
President and Chief Executive Officer

2025 performance highlights

Delivering strong results

Growth

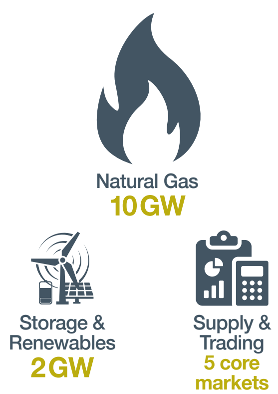
Additional ~2.2 GW of flexible generation

Value

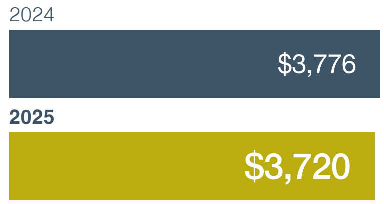
20% 10-year total shareholder return[2]

Diversification

40% – 60% capacity across Canada and U.S. assets

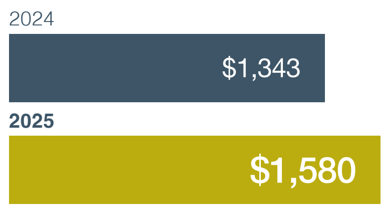


Revenues and other income ($M)

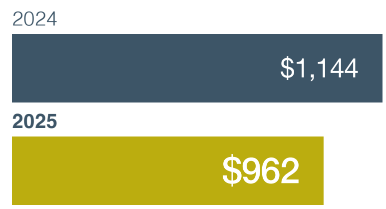


Net income ($M)

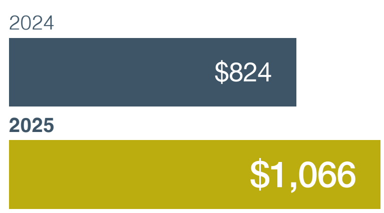
Adjusted EBITDA ($M)[1]



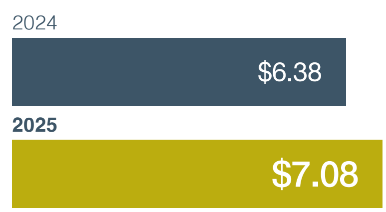
Net cash flow from operating activities ($M)



Adjusted funds from operations ($M)[1]



Adjusted funds from operations per share ($)[1]



1 Adjusted EBITDA and AFFO are non-GAAP financial measures and AFFO per share is a non-GAAP ratio. See Non-GAAP financial measures and ratios.

2 Compound annual growth rate.

2026 performance targets

Priority	2026 target[1]
Execution of major turnarounds	Sustaining capital expenditures of **$290 million to $330 million**
Generate financial stability and strength	Adjusted fund from operations[2] of **$890 million to $1,010 million**
	Adjusted EBITDA[2] of **$1,565 million to $1,765 million**
Portfolio optimization	Re-contract/contract natural gas generation
	Maximize facility asset life and value
Expand flexible generation portfolio	Continue construction of Ontario growth and commercial initiative projects
	Continue to explore opportunities to build or acquire natural gas generation facilities
Grow renewables portfolio	Continue construction of North Carolina growth projects
	Continue to explore opportunities to build or acquire renewables facilities
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

1 Performance targets for 2026 to be read in conjunction with the Forward-looking information section, which identifies the material factors and assumptions used to develop forward-looking information and their material-associated risk factors.
2 Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP financial measures and ratios.

The 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.

Our dividend growth is projected to be 2% for 2026 with a long-term targeted dividend growth guidance of 2-4% thereafter, which will fund growth opportunities. 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.

To ensure portfolio reliability, and to best position the assets to capitalize on stronger market fundamentals beyond 2026, our Alberta maintenance schedule was updated in the third quarter of 2025. In 2026, we expect approximately a 40% increase in outage days for our Canada flexible generation portfolio.

Executing our strategic focus

The energy expansion is upon us. We have the fleet. We have the people. We are market ready.

In this section:

Executing our strategic focus

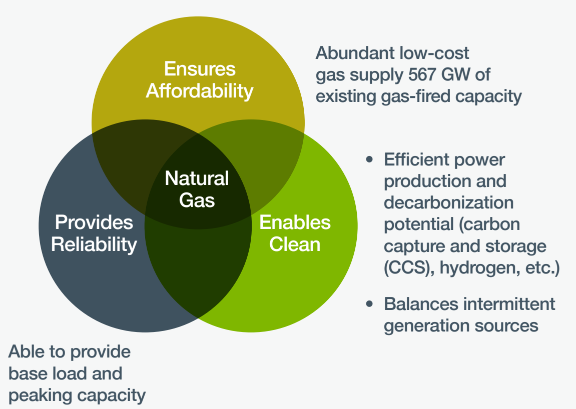
Deliberate growth, durable performance

Surging electricity demand is redefining power markets across North America. Electrification, industrial reshoring, electric vehicle adoption, and explosive data centre growth are driving durable, long-term load that is now essential to economic competitiveness. This escalating need for reliable power represents a generational opportunity, and Capital Power is ready.

Natural gas is uniquely positioned to meet today's energy needs

No technology offers more immediate scalable, capital-efficient growth than natural gas. The U.S. has vast installed natural gas capacity operating well below potential, enabling rapid increases in output without new build costs. Uprates and expansions of existing facilities provide some of the lowest-cost baseload additions available today. And while renewables, storage, and nuclear will all play a role in decarbonization, natural gas remains the flexible backbone of the system. It can ramp fast and deliver dependable baseload where and when it's needed.

Natural gas is the largest source of reliable U.S. power generation.



Our strategy: Acquire to grow, optimize to add value

Our strategy of acquiring and optimizing existing natural gas capacity directly targets the most efficient path to meeting demand while preserving reliability. With a strategically located fleet, strong contracting profile, and demonstrated ability to optimize assets into a high-performing, investment-grade platform, we are converting market disruption into a sustainable competitive advantage.

Our approach is disciplined and differentiated: grow contracted natural gas fired generation in volume, duration, and price while de-risking through commercial optimization rather than waiting on future market conditions. In an era defined by the urgent need for reliable, affordable power, our portfolio isn't just prepared for growth – it's purpose-built for it.

2030 Targets: Positioned to deliver sustained performance and value

- 50% cumulative increase in U.S. capacity (or ~3.5 GW)
- 13-15% annual Total Shareholder Return (TSR)[1]
- 8-10% annual AFFO per-share growth
- Maintain 2-4% annual dividend growth target

Armed with scale, diversification, and industry-leading operational and commercial capabilities, Capital Power is positioned to turn today's unprecedented power demand into long-term value creation.

1 Based on 2026 budget.

Executing our strategic focus

Scaling our platform

We are expanding our portfolio with disciplined, strategically aligned acquisitions that strengthen our position in attractive power markets. Over the past decade, we have invested approximately $8.5 billion to add 9 GW of natural gas generation capacity, demonstrating a proven track record of acquiring high-quality, strategically located assets that deliver immediate accretion and long-term value. Our focus on long-term contracts and strong counterparties provides stable, durable cash flows while positioning our platform for continued, scalable growth.

Establishing a foothold in North America's largest power market

In 2025, we made our largest acquisition to date, bringing two new facilities in the PJM (Pennsylvania–New Jersey–Maryland) market – Hummel Station and the Rolling Hills Generating facility – into the Capital Power portfolio. Together, they add ~2.2 GW of capacity, allowing us to establish a strong foothold in the largest and most liquid North American power market. Through the ~$3.0 billion[1] acquisition, Capital Power is now one of five North American independent power producers with over 10 GW of natural gas capacity.[2]

- **Hummel Station:** 1,124 MW, a combined cycle natural gas facility in Shamokin Dam, Pennsylvania. 663 data centres located within 200 miles[3]
- **Rolling Hills Generating facility:** 1,023 MW, a combustion turbine natural gas facility in Wilkesville, Ohio. 244 data centres located within 200 miles[3]

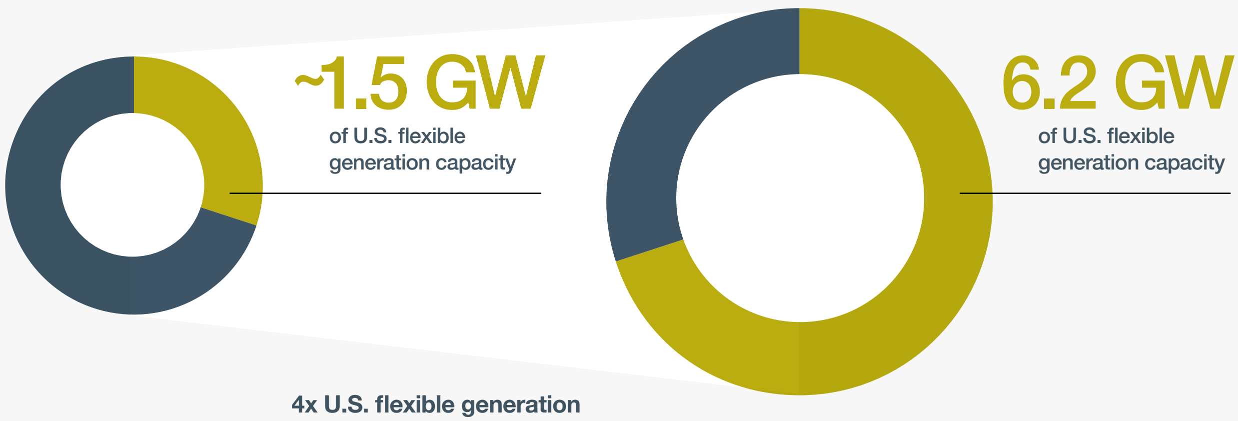
1 Converted from U.S. dollars to Canadian dollars using a 1.3890 exchange rate, as reported by the Bank of Canada on April 11, 2025.
2 Based on 2024 actual capacity factor.
3 Based on third party analysis on Data Centre Hawk data.

2022

~5.2 GW of flexible generation capacity

2025

~10.4 GW of flexible generation capacity



Executing our strategic focus

Optimizing our assets

Capital Power drives value across our fleet through a disciplined approach to operational excellence, asset optimization, and site-level improvements. By re-contracting and strategically managing our flexible generation, we unlock additional capacity, reduce costs, and lower carbon intensity, delivering the lowest cost per kilowatt across the portfolio.

We don't just buy and operate as delivered – we buy and transform our acquisitions to create optimal value. Our dedicated integration team ushers new or acquired assets into our fleet efficiently with intention, instilling our operating philosophy and moving them along the road to optimization.

Driving profitability through Genesee repowering

The Genesee Repowering project, commissioned in 2024, has strengthened profitability even amid a trough in power prices, leveraging increased operational efficiency, lower carbon costs due to CO_2 emissions reductions, and effective hedging strategies. With approximately 1.9 GW of generation capacity, Genesee remains Canada's most efficient combined-cycle gas plants, offering long-term asset life and future growth potential, including opportunities to serve expanding data centre demand.[1] Additionally, it has added 512 MW of net capacity[2] to strengthen Alberta's baseload power supply, supporting a responsible, economically sustainable energy transition. In recognition, Alberta Capital Airshed honoured Capital Power with its 2025 Clean Air Award for Contributing Toward Improving Community Air Quality.

Advancing AI-ready power in Alberta

We are progressing data centre opportunities in Alberta, including site evaluations and engagement with the Alberta Electric System Operator for co-location and potential

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

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

Executing our strategic focus
Optimizing our assets

incremental generation. In December, we signed a binding MOU with an investment-grade data centre developer for a 250 MW energy supply agreement. The long-term agreement, expected to last 10+ years, is planned to begin in 2028 and would be supported by Capital Power's Alberta-based generation portfolio. We remain confident in advancing a project that balances reliability, speed to market, and Alberta's strong generation and transmission capacity, while ensuring commercial and regulatory requirements are met.

Driving growth through strategic re-contracting

Through recontacting, we execute important life extension programs so we can deliver reliable power today and well into the future.

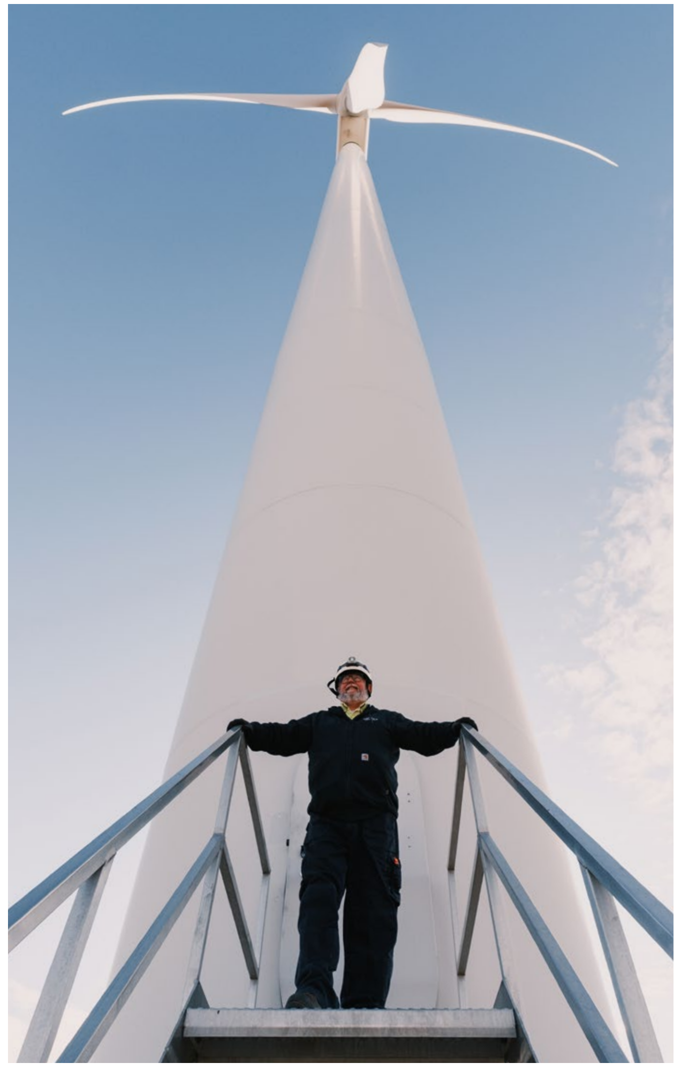
In 2025, we secured a new long-term power purchase agreement (PPA) with Consumers Energy for MCV, extending to 2040 and providing 10 years of incremental contracted revenue, subject to customary regulatory approvals. Under the PPA, MCV will receive payments for 1,240 MW, approximately 75% of the facility's capacity, starting in June 2030. It is expected to generate an estimated $140 million (US$100 million) in additional adjusted EBITDA, an 85% increase over prior contract pricing[3]. MCV is jointly owned, with Capital Power owning a 50% working interest and the remaining 50% owned by Manulife Investment Management. MCV, the largest natural gas-fired combined electric and steam generating facility in the U.S., also presents new market opportunities.

Delivering operational excellence

Capital Power's strength lies in our in-house expertise and long-standing investment in our assets, enabling us to maximize both life and efficiency – a capability that is difficult to replicate. Our operational approach combines disciplined fleet management with a culture of ownership and pride, driving performance, innovation, and long-term value creation.

We are committed to maintaining the highest standards in asset planning, performance, and safety, ensuring reliable operations and minimizing downtime. Our internal expertise allows us to continually enhance fleet efficiency and optimize resource use by:

- Increasing output and achieving higher capacity factors through strategic operational decisions, equipment upgrades, and process improvements.
- Reducing downtime and managing costs effectively through operational excellence in turnarounds, optimization, and day-to-day management.
- Optimizing fuel, water, and other resource usage to maximize operational and environmental efficiency.



This disciplined approach ensures that our assets deliver sustained value while reinforcing a culture of excellence that extends across the organization.

We have over 480 years of combined operational expertise through our plant managers alone.

3 Based on 2030 contract pricing.

Executing our strategic focus

Powering a lower-carbon future

We continue to invest in commercialized non-emitting solutions, including solar, wind, and battery energy storage systems, while exploring balanced energy and lower-carbon ventures. By diversifying across technologies, we enhance fleet resiliency and adaptability, ensuring sustainable growth through changing market cycles.

Our roadmap to a lower-carbon future

Reliable & Affordable Meet growing demand while contributing to overall energy security	**Growth:** Natural gas	**Existing fleet:** Increase output and enable high-capacity factors
Lower Carbon Reduce emissions intensity and invest in commercialized non-emitting solutions	**Growth:** Batteries Renewables Balanced energy solutions	**Existing fleet:** Lower emissions through optimization Expand utility scale storage assets
Beyond Reduce absolute emissions through investments in lower-carbon solutions	**Evaluating & exploring:** CCS SMR Lower-carbon ventures The next emerging game-changer	

Delivering 170 MW of new battery storage in Ontario

In 2025, we commissioned our first-ever battery storage projects – our York and Goreway BESS projects. Together, the projects provide up to 170 MW of storage to support grid reliability, provide backup power when needed, and meet increasing energy demand in Ontario. In addition, they will add roughly $35 million in contracted annual EBITDA for over 20 years.[1] Capital Power delivered both projects on time, under budget.

Significant strides in renewable growth

In 2025, Capital Power continued construction of our Hornet Solar project in North Carolina. Situated on approximately 525 acres, Hornet Solar is a 73 MW facility that will operate under a 25-year PPA with Duke Energy Carolinas. Commercial operations are targeted for Q3 2026.

Alongside Hornet, we are continuing to develop two additional solar projects, Maple Leaf Solar (73 MW) and Bear Branch Solar (35 MW), with commercial operations expected between Q3 2026 and Q1 2027.

These projects strengthen our North Carolina presence and demonstrate Capital Power's commitment to expanding renewable energy capacity while supporting the state's energy transition.

1 The projects are contracted until 2047 with the Ontario IESO (part of their Expedited Long-Term 1 RFP process).

Executing our strategic focus

Powering a lower-carbon future

Advancing clean energy in Alberta

In 2025, Capital Power's Halkirk 2 Wind facility began commercial operations in Alberta. The facility will provide approximately 250,000 MWh of electricity annually to help meet the power needs of all federal government buildings in the province as part of a supply agreement with Public Services and Procurement Canada in place until December 31, 2045. This represents approximately 49% of the facility's output. Capital Power also entered into a participation and equity option agreement with the Louis Bull Tribe, Samson Cree Nation, Montana First Nation and Ermineskin Cree Nation for the facility.

Renewables: Project portfolio update

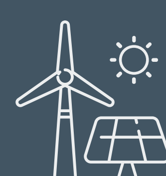
4 Projects

Alberta & North Carolina

2025–2027 Completion timeline

305 MW Total net incremental generation capacity

125 MW Wind capacity



180 MW Solar capacity

Governance and risk management

Transparency, integrity, and accountability anchor how we operate and help us earn the trust of our stakeholders.

In this section:

Corporate governance

Our commitment to responsible, accountable, and transparent corporate governance underpins long-term performance and strengthens investor confidence.

Board governance

Strong corporate governance begins with our Board, whose integrity, expertise, and experience ensure that our actions align with our values and support sound decision-making for the benefit of all stakeholders. The Board establishes corporate governance policies and practices that define expectations and accountabilities, ensuring our business is conducted ethically and effectively.

Our independent directors provide leadership, guidance, and oversight to the CEO and management team. Their key responsibilities include overseeing strategy, succession planning for the Board and CEO, executive compensation, shareholder reporting, and approving significant Company decisions. As of December 31, 2025, our Board comprised of nine independent directors alongside our CEO.

The Board has three standing Committees:

- **Audit Committee,**
- **People, Culture, and Governance (PCG) Committee, and**
- **Health, Safety, and Environment (HSE) Committee.**

For more on our corporate governance, please see our Management Proxy Circular and our **website**.

Board diversity

Capital Power recognizes and embraces the benefits of having a diverse Board of Directors and sees enhancing and maintaining diversity at the Board level as essential to our competitive advantage. Our Board Diversity Policy requires that we consider candidates on merit against objective criteria and with due regard for the benefits of diversity. In final nomination decisions, extra weight will be given to qualified female candidates and qualified candidates who bring diversity beyond gender.

Executive leadership team

Capital Power's Executive Team leads the organization toward its goals of operational excellence, community stewardship, sustainability, and innovation. Experts in the industry, our executives guide Capital Power employees to work together to safely deliver balanced energy solutions for our customers.

Governance and risk management
Corporate governance

Board of Directors[1]

Left to right:

George Williams, Carolyn Graham, Keith Trent, Barry Perry, Jill Gardiner, Gary Bosgoed, Kelly Huntington, Avik Dey, Jane Peverett, Neil H. Smith

Executive Team[1]

Left to right:

Jason Comandante
Senior Vice President, Supply & Trading

Pauline McLean
Senior Vice President, External Relations, Chief Legal Officer & Corporate Secretary

Steve Wollin
Senior Vice President, Chief Operations Officer

Avik Dey
President and Chief Executive Officer

Ferio Pugliese
Senior Vice President, Chief Corporate Officer

Scott Manson
Interim Senior Vice President, Finance & Chief Financial Officer

May Wong
Senior Vice President, Energy Markets & Low Carbon Solutions

1 Board of Directors and Executive Team as of January 1, 2026

Our approach to risk management

Risk management is a shared responsibility, from the Board to every employee. Our Code of Conduct and Enterprise Risk Management (ERM) program, together with strong corporate governance, form the foundation of our risk-aware culture.

Code of Conduct

We have replaced the former Ethics Policy with our Code of Conduct, with changes focused on increasing ease of understanding to support adoption and incorporation of Capital Power's of North Star behaviors. The Code of Conduct guides behaviour and helps employees, contractors, agents, and the Board prevent misconduct. By offering clear direction, practical tools, and guidance, it supports risk mitigation and safeguards the interests of Capital Power, our customers, shareholders, and other stakeholders.

Enterprise Risk Management

Effectively managing risk is critical to maximizing shareholder value. We believe that risk management is everyone's responsibility, from the Board to individual employees. ERM is a process and a tool that facilitates the coordination of activities to manage risk, create value, improve performance, foster innovation, and achieve strategic goals. It goes beyond risk avoidance by identifying priorities and opportunities. An effective ERM program is integrated seamlessly across all facets of the organization, embedding risk-aware thinking into strategic planning, budgeting processes and key strategy committees.

Our ERM program is based on the Committee of Sponsoring Organizations of the Treadway Commission (COSO) standard for risk management. It uses a systematic approach to identify, manage, report and monitor risk. It is updated quarterly, considering current and emerging risks for reporting to the Senior Leadership Team and the Board.

Identifying and managing risk

At Capital Power, we believe identifying, assessing, and monitoring potential risks across all stages of the value chain helps us mitigate them proactively and maximize opportunities.

Through our ERM Program, we identify, evaluate, report, and monitor key upstream, operational, and downstream risks that may affect the achievement of the Company's strategic and business objectives. This includes climate-related risks related to fuel supply, extreme weather events, changing social behaviours, and other transition risks. With subject matter experts, we assess risks and opportunities from emerging regulations associated with climate change quarterly.

Every year, the Board reviews and approves the Company's risk tolerances, ERM Policy, and risk management processes and accountabilities. In addition, the Board receives a comprehensive ERM review quarterly. Ultimately, the President and CEO is accountable for identifying and managing our risks, including climate-related risks, and approving the ERM framework. Refer to the Risks and risk management section of the Business report for more details on the key risks to our business.

Powering a brighter future

We are committed to cultivating a diverse, inclusive, and safe workplace, managing our impacts on the environment, and supporting thriving communities.

In this section:

Powering a brighter future

Our people and culture

Our progress towards Powering Change by Changing Power™ is driven by a highly skilled, agile, and engaged team committed to innovation and excellence. Creating an environment where people feel comfortable and confident being their authentic selves at work is essential to our success.

WE Lead: Driving inclusion and impact

In 2025, WE Lead – our employee resource group focused on women's empowerment – marked its third year. The group led donation drives for women's shelters in the communities where we operate, convened employee panels that showcased internal talent and career stories, and hosted a workshop to equip employees with practical tools for navigating difficult conversations. Through education, empowerment, and advocacy, WE Lead is cultivating a safe, inclusive space for female-identifying employees and allies while strengthening leadership capability across Capital Power.

For the sixth straight year, we're honoured to be included on *The Globe and Mail's* Women Lead Here list.

Driving performance through employee engagement

A career in STEM

As Plant Manager at MCV's Midland Site, Kristi Gledhill exemplifies perseverance, versatility, and a commitment to lifelong learning. Prior to joining Capital Power, she built her career by rising through the ranks in manufacturing – from entry-level roles to managing several warehouses across the United States and found her passion in leading large teams. When the demands of travel no longer fit with life as a mother of a young daughter, she stepped away from the industry and, just three months later, found her way to a new industry and new company in power generation at MCV. Since joining in 2016, she has held a variety of leadership roles including Supply Chain Manager, EHS Manager, and Operations & Maintenance Manager before stepping into her current role as Plant Manager.

Kristi is driven by a desire to be a great leader, lifelong participation in mentorship, and a passion for tackling challenges that initially seem impossible. Some of her proudest moments are when her team joins forces to innovate, ask hard questions, and push beyond perceived limits. Looking ahead, she is energized to contribute to the Company's success: "It's such an exciting time," she says. "It will allow our creative and innovative sides to shine while growing our strength as an enterprise – and I'm here for it."

Connecting and inspiring women in energy

Capital Power leaders participated in the Executive Women in Energy Conference in Canmore, Alberta, sharing insights on data centres, nuclear energy, Genesee repowering, policy, leadership, and the future of energy. Capital Power was proud to sponsor the event, hosted by Morgan Stanley.

Health, safety, security, and environment (HSSE)

The health, safety, and security of our employees is paramount at Capital Power. So, too, is working to responsibly manage our environmental impact.

Achieved an HSE Performance Index of 1.14 exceeding our target of 1.0.

A modern, risk-driven HSSE approach

Capital Power is undergoing a comprehensive HSSE transformation to strengthen agility and resilience across our operations. Our approach is built on a risk-based environmental, health, and safety management system framework designed for a dynamic, evolving business model. This framework provides flexibility within defined boundaries, enabling alternative solutions that deliver equivalent protection while maintaining mandatory controls for high-consequence risks.

We are embedding human and organizational performance principles and adopting a safety classification and learning model to sharpen our focus on high-energy hazards and critical controls. By doing so, we are strengthening our culture of learning, collaboration, and operational excellence.

Core transformation elements

- Simplified, outcome-focused requirements that support diverse technologies and decentralized operations.
- Prioritizing high-energy hazards and critical controls for proportional, meaningful learning.
- Embedding human-centered design, fostering collaboration and systemic improvement.

We promote proactive safety among our employees and contractors through in-field leadership engagement, hazard reviews, contractor management, and HSE inspections.
We measure leading performance indicators through our HSE Performance Index. For more than a decade, we have met or exceeded our target.

Emissions management

We are committed to accurately and transparently reporting on our environmental performance, including greenhouse gas (GHG) emissions.

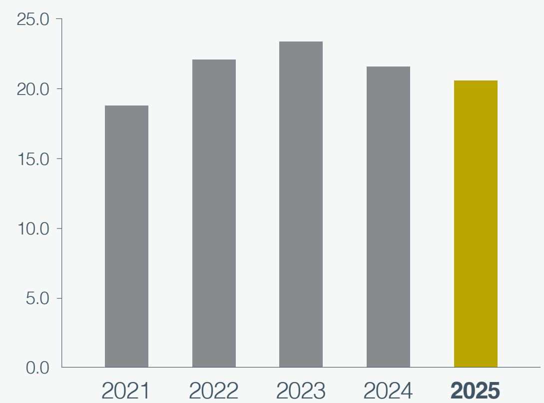
We continue to optimize our existing power plants through operational improvements and invest in technologies and infrastructure to reduce emissions for utility-scale power generation. While the continued growth of our fleet may lead to increased absolute emissions, we anticipate that higher generation levels will result in a reduced overall emissions intensity in the future.

Scope 1

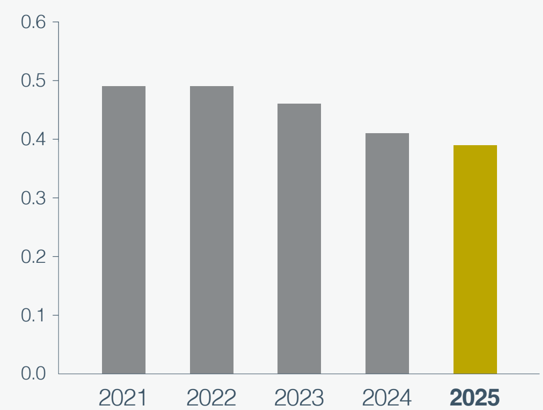
The charts on this page illustrate Scope 1 emissions across our fleet on an absolute and intensity basis.[1] Scope 1 emissions in 2025 were 20.5 $MtCO_2e$ ☑ representing a decrease from our 2024 revised emissions.[2] Emissions reductions were largely driven by completing the first full year of generation after phasing out coal and a general balance of generation shifting to lower intensity power plants.

GHG intensity in 2025 was 0.39 tonnes CO_2e/MWh ☑. The decrease in emissions intensity compared to 2024 is largely the result of higher production from lower emission intensity powerplants. Overall, net generation increased by approximately 2% while emissions decreased by approximately 5%.

GHG emissions – Scope 1 absolute[a] ($MtCO_2e$)



Scope 1 emissions intensity[b] (tCO_2e/MWh)



a 2021 revision from 13.7 to 15.6 $MtCO_2e$. 2022 revision from 15.9 to 18.1 $MtCO_2e$. 2023 revision from 16.2 to 18.8 $MtCO_2e$.

b 2021 revision from 0.52 to 0.51 $MtCO_2e/MWh$. 2022 revision from 0.51 to 0.50 $MtCO_2e/MWh$. 2023 revision from 0.48 to 0.47 $MtCO_2e/MWh$.

1 We follow GHG Protocol guidance to revise historic emissions in the event of structural changes to the organization and/or changes in calculation methodology, and restate emissions in the event of discovery of errors that would otherwise impact the consistency and relevance of reported emissions information.

2 We have revised Scope 1 absolute emissions and intensity for 2021 through 2024 to depict facility acquisitions of Frederickson 1, La Paloma, Harquahala, Hummel Station, and Rolling Hills.

Powering a brighter future
Emissions management

Scope 2

Location-based Scope 2 emissions for 2025 were 0.07 $MtCO_2e$. Our Scope 2 emissions have increased compared to 2024 primarily as a result of acquisitions and higher reliance on imported power at Genesee after repowering.

We manage the impact of our Scope 2 emissions through a combination of participation in Alberta's Technology Innovation and Emissions Reduction Regulation compliance program and the retirement of renewable energy certificates and carbon offsets.

Powering community

We aim to develop and operate power facilities that reflect community priorities, strengthen local relationships, and create positive, lasting impacts.

Our engagement with stakeholders and local communities is early and ongoing, from development planning through decommissioning, using multiple channels including conversations, events, newsletters, and email.

Guided by input from community members and employees, we invest in our communities. In 2025, Capital Power contributed $3.7 million to community organizations, with our employees donating more than $325,000 through our employee matched-giving programs.

Find out more about our community investment on our **website**.

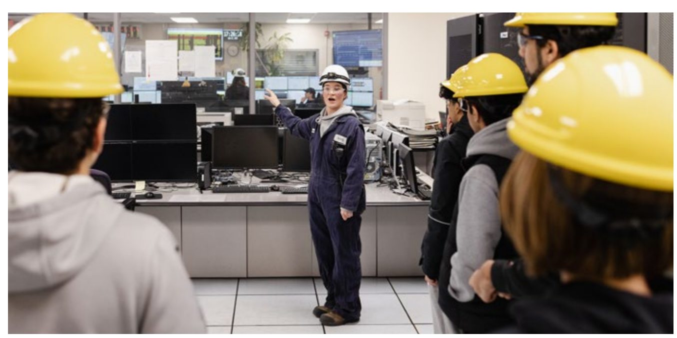
Supporting local farmers and biodiversity

We're proud to partner with the Canadian non-profit ALUS to help farmers and ranchers in Wetaskiwin and Leduc counties, Alberta, enhance biodiversity. With support from Capital Power, they have planted 36 acres of trees and shrubs, improving soil and water health and sequestering an estimated 355 tonnes of carbon over five years. Rooted in community and collaboration, this partnership also fosters knowledge sharing and learning as farmers adopt resilient agricultural practices.

We are committed to meaningful, active engagement, understanding community priorities, and delivering collaborative solutions.

From parts to purpose: Our Renewables team joined together with members of our Phoenix office for a unique challenge – building bikes for kids from their raw parts. Along with helmets decorated by our teams, we donated 12 fully assembled new bikes to the Military Family Readiness Center, which supports families new to the community.

Battling hunger: Employees from our U.S. headquarters in Phoenix volunteered at St. Mary's Food Bank, packing 3,816 emergency food boxes and 376 large family boxes.



Powering curiosity: We welcomed kids and young adults from Big Brothers, Big Sisters to our Goreway site with a facility tour and talk on what it takes to run a power plant.

Powering a brighter future
Powering community

Learning, growing and partnering with Indigenous communities

Capital Power is committed to reconciliation with Indigenous Peoples. Guided by our ReconciliAction Plan, we focus on:

- Expanding awareness internally through company-wide cultural sessions, purposeful event sponsorship, and employee volunteering opportunities in communities – including our partnership with Bears' Lair, where for the sixth year we hosted an Indigenous Youth Entrepreneur Dream camp to foster the spirit of entrepreneurship in Indigenous youth, and our partnership with the Canadian Football League (CFL) to honour the National Day for Truth Reconciliation.
- Building relationships and deepening our learning and understanding of culture, values and priorities through attending and supporting community events and national conferences.
- Supporting capacity and economic opportunities through contracting, partnerships and employment, as well as offering scholarships to Indigenous youth and students in Alberta, British Columbia, and Ontario.

As part of our efforts to examine the feasibility of developing and deploying grid-scale small modular reactor nuclear generation with our partner Ontario Power Generation (OPG), in 2025 we met with 30 Indigenous communities in Alberta and toured over 40 available community members of the Darlington Nuclear Generating facility in Ontario. The tours included discussions about how nuclear energy is generated, safety and security measures, and how used nuclear fuel is managed.

Activating community spirit: Together with the Edmonton Oilers Entertainment Group, we launched the *Oil Country Powers Change* campaign, encouraging high school students across northern and central Alberta to make community impact through volunteerism, mentorship, and local service activities.

Empowering Indigenous youth through sport and recognition

In 2025, Capital Power partnered with the CFL to honour the National Day for Truth and Reconciliation, sponsoring two reconciliACTION initiatives to strengthen connections with Indigenous communities through sport.

Together with the Edmonton Elks and Hamilton Tiger-Cats, we hosted youth flag football clinics with the Enoch Cree Nation, Paul First Nation, Samson Cree Nation, and Six Nations of the Grand River. As Official Partner of the CFL's Truth and Reconciliation Donation program, Capital Power also matched $30,000 in sales from the 2025 New Era sideline collection, supporting Indigenous Youth Roots in providing programs and opportunities for Indigenous youth across Canada.

Learn more about Indigenous relations at Capital Power on our website.

Business report

This Business report, prepared as of March 3, 2026, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2025 and December 31, 2024, the annual information form of Capital Power Corporation for the year ended December 31, 2025 and the remainder of the Integrated Annual Report (IAR), including both the sections preceding this Business report and the cautionary statements regarding Forward-Looking Information in the section following this Business report.

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

In this Business report, financial information for the years ended December 31, 2025, 2024 and 2023 is based on the audited consolidated financial statements of the Company 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 Business report and recommends its approval by the Board of Directors. The Board of Directors approved this Business report as of March 3, 2026.

Performance overview

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 earnings before interest, taxes, depreciation, and amortization (EBITDA), adjusted funds from operations (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.

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

Priority	2025 targets	Status at December 31, 2025
Deliver		
Execution of major turnarounds	Sustaining capital expenditures of **$215 million to $245 million**[2]	**$238 million**[1]
Generate financial stability and strength	▸ AFFO[2,3] of **$950 million to $1,100 million** ▸ Adjusted EBITDA[2,3] of **$1,500 million to $1,650 million**	**$1,066** million **$1,580** million
Portfolio optimization and integration	Re-contract/contract flexible generation Maximize facility asset life and value	In Q3 2025, the Company executed a new long-term contract with improved economic terms for Midland Cogeneration, extending to 2040 and providing 10 years of incremental contracted revenue (see Significant Events). Discussions with counterparties for other flexible generation facilities are in progress.
Build		
Expand flexible generation portfolio	Continue construction on Ontario growth and commercial initiative projects Continue to explore opportunities to build or acquire flexible generation facilities	Construction is underway and the projects remain on track to meet their targeted completion dates (see Capital Expenditures and Investments). Reached commercial operation of the uprate projects at Goreway and York Energy resulting in an addition of approximately 60 MW, reflective of Capital Power's ownership increase in York Energy. The Ontario Battery Energy Storage System (BESS) projects achieved commercial operations in Q3 2025. East Windsor Expansion environmental permits have been received and all major equipment is on site. Site civil work and foundations are advanced. In Q2 2025, the Company completed the acquisition of two U.S. flexible generation assets in the Pennsylvania-New Jersey-Maryland (PJM) market, Hummel Station, LLC (Hummel Station) and Rolling Hills Generating, LLC (Rolling Hills) (see Significant Events).
Grow renewables portfolio	Continue construction on Alberta and North Carolina growth and commercial initiative projects Continue to explore opportunities to build or acquire renewables facilities	Halkirk 2 Wind achieved commercial operation in December 2025. Construction for Hornet Solar continued into 2025. Bear Branch Solar and Maple Leaf Solar commenced construction in the second quarter of 2025. These projects remain on schedule for targeted completion (see Capital Expenditures and Investments).
Create		
Balanced energy solutions	Evaluate Small Modular Reactors (SMRs) in Alberta	Pre-feasibility study work for the Alberta SMR project with Ontario Power Generation (OPG) remains on track. The first funded phase of the pre-feasibility study for the Alberta SMR project with OPG has been completed. Our partnership with OPG on the project continues to progress as planned and recently we extended our commitment for another two years to continue with the collaboration. We continue to evaluate the development opportunity through this project. We executed on and announced an Alberta memorandum of understanding (MOU) with a data centre customer and continue to progress marketing other sites (see Significant Events).
	Provide integrated energy solutions to commercial and industrial customers	Discussions with counterparties are in progress to provide integrated energy solutions.

1 Includes our share of equity-accounted investments sustaining capital expenditures of $62 million net of partner contributions of $9 million.

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

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

Performance overview

The Board of Directors has approved a 6% increase in the common share dividend for 2025. Our dividend payout target is within the range of 30% to 50% of AFFO. Each annual increase is premised on the assumptions listed under Forward-Looking Information and subject to approval by the Board at the time of the increase.

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

Non-GAAP financial measures and ratios

Capital Power uses (i) earnings before income tax expense, depreciation and amortization, net finance expense, foreign exchange gains or losses, gains or losses on disposals and other transactions, unrealized changes in fair value of commodity derivatives and emission credits, other expenses from our 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

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

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

	Three months ended December 31,		Year ended December 31,	
($ millions)	**2025**	2024	**2025**	2024
Net (loss) income	**(13)**	242	**159**	701
Depreciation and amortization	**159**	137	**580**	503
Unrealized changes in fair value of commodity derivatives and emission credits	**166**	48	**342**	(238)
Acquisition and integration costs	**–**	–	**41**	10
Foreign exchange (gain) loss	**(5)**	20	**(21)**	29
Net finance expense	**90**	61	**307**	221
(Gain) loss on disposals and other transactions	**(2)**	11	**10**	31
Items from equity-accounted investments[1]	**40**	32	**150**	123
Other non-recurring items[2]	**–**	43	**4**	47
Gain on divestiture	**–**	(309)	**–**	(309)
Impairment	**–**	–	**–**	27
Income tax (recovery) expense	**(21)**	45	**8**	198
Adjusted EBITDA[3]	**414**	330	**1,580**	1,343

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

2 For the year ended December 31, 2025, other non-recurring items reflects costs related to the end-of-life of Genesee coal operations of $4 million. For the three months and year ended, December 31, 2024 other non-recurring items reflects restructuring costs of $39 million and costs related to the end-of-life of Genesee coal operations of $4 million and $8 million, respectively.

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

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. During the second quarter of 2025, the Company amended the composition of AFFO and AFFO per share to exclude acquisition and integration costs, as these costs are not reflective of cash generated from facility operations. The Company has applied this change to all historical amounts reported.

AFFO represents net cash flows from operating activities adjusted to:

- 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 cash from off-coal compensation received annually through to 2030,
- 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,
- exclude 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:

	Three months ended December 31,		**Year ended December 31,**	
($ millions)	**2025**	2024	**2025**	2024
Net cash flows from operating activities per consolidated statements of cash flows	**205**	438	**962**	1,144
Add (deduct):				
Interest paid	**102**	31	**304**	163
Change in fair value of derivatives reflected as cash settlement	**1**	4	**8**	(13)
Realized gain on settlement of interest rate derivatives	**–**	–	**(17)**	(42)
Distributions received from equity-accounted investments	**(19)**	(96)	**(66)**	(120)
Miscellaneous financing charges paid[1]	**3**	–	**1**	(6)
Income taxes paid	**34**	21	**20**	38
Change in non-cash operating working capital	**30**	(166)	**7**	(173)
	151	(206)	**257**	(153)
Net finance expense[2]	**(71)**	(50)	**(263)**	(186)
Current income tax recovery (expense)[3]	**38**	(2)	**110**	(31)
Sustaining capital expenditures[4]	**(91)**	(56)	**(176)**	(152)
Preferred share dividends paid	**(7)**	(7)	**(27)**	(31)
Cash received for off-coal compensation[5]	**–**	–	**60**	50
Remove tax equity interests' respective shares of AFFO	**(1)**	(2)	**(5)**	(6)
AFFO from equity-accounted investments	**28**	18	**129**	117
Acquisition and integration costs[6]	**(1)**	–	**40**	7
Other non-recurring items[7]	**(7)**	49	**(21)**	65
AFFO[8]	**244**	182	**1,066**	824
Weighted average number of common shares outstanding (millions)	**155.8**	132.1	**150.5**	128.9
AFFO per share ($)[8]	**1.57**	1.38	**7.08**	6.38

1 Included in other cash items on the 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. Net finance expense also excludes $9 million related to the loss on the interest rate swap from the early settlement of the Goreway debt (see Significant Events).
3 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 Includes sustaining capital expenditures net of partner contributions of $1 million and $9 million for the three months and year ended December 31, 2025, respectively, compared with $1 million and $9 million for the three months and year ended December 31, 2024, respectively.
5 Reflects annual off-coal compensation payments received from the Government of Alberta (GoA). For the year ended December 31, 2025, an additional payment was received for the settlement of previously disputed off-coal compensation payments as described in the Company's 2025 annual consolidated financial statements.
6 For the year ended December 31, 2025, net of current income tax recoveries of $3 million, compared with $3 million for the year ended December 31, 2024.
7 For the three months ended December 31, 2025, other non-recurring items reflect income tax recoveries of $7 million related to other non-recurring items recognized in the current and prior periods. For the year ended December 31, 2025, other non-recurring items reflect costs related to the termination of one of the Halkirk 2 Wind virtual power purchase agreement (VPPA) and end-of-life of Genesee coal operations of $5 million each, net of current income tax recoveries of $31 million related to other non-recurring items recognized in the current and prior periods. For the year ended December 31, 2024, other non-recurring items reflects costs of $39 million, costs related to the end-of-life of Genesee coal operations of $9 million and a provision of $18 million for discontinuation of the Genesee CCS project related to termination of sequestration hub evaluation work (see Significant Events) net of current income tax recovery of $1 million related to other non-recurring items recognized in the prior and current periods. For the three months ended December 31, 2024, other non-recurring items reflect restructuring costs of $39 million, costs related to the end-of-life of Genesee coal operations of $4 million, net of current income tax expense of $6 million related to other non-recurring items recognized in the prior and current periods. Restructuring costs above exclude related employee benefit costs that would have otherwise been incurred in future periods.
8 AFFO is a non-GAAP financial measure and AFFO per share is a non-GAAP ratio. See Non-GAAP Financial Measures and Ratios.

Financial highlights

($ millions, except per share amounts)	Year ended December 31, 2025	2024	2023
Revenues and other income	**3,720**	3,776	4,282
Net income	**159**	701	737
Net income attributable to shareholders of the Company	**160**	699	744
Basic earnings per share ($)	**0.88**	5.16	6.07
Diluted earnings per share ($)[1]	**0.88**	5.15	6.04
Adjusted EBITDA[2]	**1,580**	1,343	1,458
AFFO[2]	**1,066**	824	821
AFFO per share ($)[2]	**7.08**	6.38	7.01
Net cash flows from operating activities	**962**	1,144	822
Purchase of property, plant and equipment and other assets, net	**864**	1,070	723
Dividends per common share, declared ($)	**2.6858**	2.5338	2.3900
Dividends per Series 1 preferred share, declared ($)	**0.6553**	0.6553	0.6553
Dividends per Series 3 preferred share, declared ($)	**1.7151**	1.7151	1.3633
Dividends per Series 5 preferred share, declared ($)	**1.6577**	1.6577	1.4836
Dividends per Series 11 preferred share, declared ($)[3]	**N/A**	0.7188	1.4375
	At December 31,		
	2025	2024	2023
Loans and borrowings including current portion	**6,730**	4,976	4,716
Total assets	**15,441**	12,930	11,156

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

Revenues and other income for the year ended December 31, 2025, were consistent with 2024, primarily due to increased revenues from the U.S. flexible generation segment due to the Hummel Station and Rolling Hills facilities acquired in June 2025 (see Significant Events) and increased revenues from La Paloma acquired in February 2024. The increase is offset by losses on unrealized changes in fair value of commodity derivatives and emission credits compared to gains in the prior year.

Net income for the year ended December 31, 2025, was lower than last year due to the net impacts of:

- changes in revenues and other income described above and changes in adjusted EBITDA described below,
- unfavourable changes in unrealized changes in fair value of commodity derivatives and emission credits,
- increased net finance expense due to increased long term borrowings in the current year,
- higher depreciation and amortization, primarily due to the acquisition of the Hummel Station and Rolling Hills facilities in the second quarter of 2025, and the commissioning of Genesee Repower 1 and 2 in the fourth quarter of 2024,
- increased other administrative expenses including acquisition and integration costs,
- a gain on divestiture in the prior year from the partial sale of Quality Wind and Port Dover and Nanticoke Wind,
- offset by lower income tax expense in the current year, primarily due to lower overall consolidated net income before tax, and
- offset by foreign exchange differences due to gains in the current year compared to losses in the prior year.

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 for the year December 31, 2025, was higher than the corresponding period in 2024 largely due to the net impact of:

- higher contributions from the U.S. flexible generation segment due to the Hummel Station and Rolling Hills facilities which were acquired in June 2025 (see Significant Events), and the full year results from La Paloma and Harquahala which were acquired in February 2024, partially offset by lower results from Midland Cogeneration due to lower revenue from a capacity rate reduction in the power purchase agreement (PPA) contract and increased fuel costs resulting in lower dispatch,
- lower emissions costs in the Canada flexible generation segment driven by the repowering of Genesee Generating Station to be off coal,
- lower corporate expenses driven by lower salary costs that resulted from a reorganization late in 2024,
- partially offset by lower contributions from the Canada renewables segment due to the sell down of Quality Wind and Port Dover and Nanticoke facilities in the fourth quarter of 2024.

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.

Financial highlights

AFFO for the year ended December 31, 2025, was higher than the corresponding period in 2024, primarily due to:

- higher adjusted EBITDA described above,
- decreased current income tax expense mainly due to tax depreciation and lower overall consolidated net income before tax, and
- partially offset by higher finance expense from increased loans and borrowings.

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 is discussed in Liquidity and Capital Resources.

Significant events

$4.2 billion (US$3.0 billion) investment partnership with Apollo Funds

In December 2025, Capital Power entered into a MOU with Apollo Global Management (Apollo Funds) to form an investment partnership to pursue the acquisition of merchant U.S. natural gas generation assets, with total potential committed equity of up to US$3 billion (including US$750 million from Capital Power). The partnership combines Apollo Funds' capital strength with Capital Power's operating and commercial expertise to accelerate Capital Power's U.S. natural gas growth strategy and expand earnings.

The MOU contemplates a partnership with Capital Power operating acquired assets and receiving management and performance fees.

Alberta data centre MOU

In December 2025, the Company entered into a binding MOU with an investment grade data centre developer for a 250 MW Electricity Supply Agreement (ESA). The long-term ESA (10+ years) has an anticipated start date in 2028 and would be backed by Capital Power's Alberta-based power generation portfolio. If a final agreement between the parties cannot be reached, a termination fee will be paid to Capital Power.

$600 million offering of medium-term notes and redemption of January 2026 medium-term notes

On November 14, 2025, Capital Power completed a public offering in Canada of unsecured medium-term notes (Notes) in the aggregate principal amount of $600 million. The Notes have an interest rate of 4.231% and mature on January 14, 2033. Capital Power used the net proceeds to repay, redeem and refinance existing indebtedness, which included fully funding the redemption of the Company's January 2026 Notes, as well as project level debt at Goreway Power Station, Capital Power's credit facilities, and for general corporate purposes.

On November 5, 2025, Capital Power issued a notice of redemption in respect of all of its outstanding 4.986% medium-term notes, due January 23, 2026 (January 2026 Notes), for redemption on November 23, 2025 (Redemption Date) in accordance with the trust indenture governing the January 2026 Notes. The aggregate principal amount of January 2026 Notes outstanding was $300 million. The redemption price was $1,000 per $1,000 principal amount of the January 2026 Notes redeemed, plus accrued and unpaid interest to, but excluding, the Redemption Date. As November 23, 2025 was not a business day, payment of the redemption price occurred on November 24, 2025.

CFO update

On October 29, 2025, Sandra Haskins, SVP Finance & CFO announced her plans to retire from her role on December 31, 2025 after a 23-year tenure. Sandra has played a pivotal role in shaping the strategic direction and successful growth of Capital Power. Scott Manson, Chief Accounting Officer has transitioned to Interim SVP Finance & CFO. A successor was announced in February 2026 (see Subsequent Events). Sandra will support a smooth leadership transition by remaining in an advisory capacity until the end of Q1 2026.

York and Goreway Battery Energy Storage Systems commissioned and contracted to 2047

On September 22, 2025, 120 MW York BESS and 50 MW Goreway BESS projects successfully achieved commercial operations. A leader of Ontario's BESS development, Capital Power delivered both projects on time, under budget. The projects are contracted until 2047 with the Ontario Independent Electricity System Operator (IESO) (part of their Expedited Long-Term 1 RFP process) and will add approximately $35 million in annual adjusted EBITDA over the contract term. These facilities enhance our portfolio of flexible generation sources that provide grid stability, support the integration of renewable resources, and meet the province's growing demand for electricity.

Midland Cogeneration Venture (MCV) with Consumers Energy to 2040

In September 2025, Capital Power successfully executed a new long-term contract with improved economic terms for MCV with Consumers Energy, extending to 2040 and providing 10 years of incremental contracted revenue, subject to customary regulatory approvals. MCV is the largest natural gas-fired combined electric and steam generation facility in the U.S., and a cornerstone of reliable power generation in Michigan. MCV will receive payments for 1,240 MW, approximately 75% of the facility's capacity starting in June 2030 under the new PPA, creating long-term revenue stability throughout the contract term. The contract is expected to generate a gross increase in full year adjusted EBITDA for the facility of approximately $140 million (US$100 million) annually representing an 85% increase over current contract pricing. MCV is jointly owned, with Capital Power owning a 50% working interest and the remaining 50% owned by Manulife Investment Management.

Significant events

MCV data centre

In September 2025, MCV entered into a term sheet with a leading data centre developer for the potential development of a data centre adjacent to the facility. While the parties are no longer exclusive, the Company is continuing its discussions with the developer to execute a long term PPA for 250MW of power for up to 15 years.

Virtual power purchase agreement cancellation

The Company previously announced that on March 27, 2024, it had entered into a 15-year VPPA with Saputo Inc. (Saputo). As a result of delayed commissioning on Halkirk 2 Wind, Saputo elected to terminate the VPPA with Capital Power, resulting in a $5 million penalty paid in the third quarter of 2025. The termination also resulted in an unrealized mark-to-market loss of $8 million upon unwinding of the VPPA in the third quarter of 2025. Despite the contract with Saputo representing 45% of plant output, Capital Power expects the financial impact to be minimal due to forecasted merchant pricing exceeding the Saputo VPPA pricing. Halkirk 2 Wind achieved commercial operation in December 2025.

$1.5 billion credit facility and $600 million revolving credit facility

On June 6, 2025, the Company terminated its $300 million unsecured club credit facility, increased the capacity of its committed credit facility from $700 million to $1.5 billion, and extended the term from 2029 to 2030. On August 8, 2025, the Company entered into a two-year revolving credit agreement with a total commitment of $600 million, maturing in 2027. The funds can be drawn in Canadian or U.S. dollars. Interest is floating and is based on the type of draw, plus margin.

Acquisition of Hummel Station and Rolling Hills

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

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

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

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

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

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

One unit at the Rolling Hills facility was out of service as a result of a Generator Step Up (GSU) transformer fire on or about September 12, 2024 while awaiting procurement of a replacement GSU. The unit was fully restored in December 2025. Lost revenues associated with the unit were negotiated as part of the purchase price, and the Company has insurance coverage for the cost of the replacement GSU.

The total purchase price of the Acquisition was $3.0 billion (US$2.2 billion) in total cash consideration, including working capital and other closing adjustments. Capital Power partially financed the acquisition with net proceeds from an offering of common shares and a private offering of senior notes, described in further detail below. The balance of the Acquisition was funded with additional cash on hand and a drawdown on the Company's existing revolving credit facilities.

PJM posted their Base Residual Auction (BRA) results for the 2026/2027 and 2027/2028 delivery years on July 22, 2025 and December 17, 2025, respectively. The auctions secured commitments for approximately 134 GW of unforced capacity in the Regional Transmission Organization from annual, summer-period and winter-period matched resources and price-responsive demand. Prices for all locational deliverability areas (LDAs), including the LDAs where the Rolling Hills and Hummel Station facilities are located, cleared at the caps of US$329/MW-day for 2026/2027 and US$333/MW-day for 2027/2028, supporting the economics of the Acquisition.

Significant events

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

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

$667 million bought deal offering of common shares

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

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

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

Subsequent events

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, crossborder transactions, energy trading and diverse regulatory landscapes. Scott Manson, who has served as Interim CFO, will continue to support the onboarding process and assist Mr. MacIntosh until the end of April 2026.

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$8M 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 MWs will be added in 2026 and an additional 25 MWs in 2027. This investment will strengthen Arlington's ability to provide reliable power during Arizona's peak summer demand.

Facilities and portfolio optimization

Facility category and facility	Type of facility	Year commissioned	Net generation capacity (MW) Facility	Net generation capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Canada flexible generation						
Genesee Generating Station, Alberta[1]	Natural gas-fired combined cycle	2024 (Units 1 and 2 repowered) 2005 (Unit 3)	1,857	1,857	Merchant	–
Clover Bar Energy Centre, 1, 2 and 3, Alberta	Natural gas-fired simple cycle	2008 (Unit 1) 2009 (Units 2 and 3)	243	243	Merchant	–
Clover Bar Landfill Gas, Alberta	Landfill gas-fired	2005	2	2	Merchant	–
Joffre, Alberta	Natural gas-fired combined cycle cogeneration	2001	480	192	Merchant	–
Shepard, Alberta	Natural gas-fired combined cycle	2015	881	440	Merchant with tolling agreement for 50% of owned capacity	2035 (tolling agreement)
Island Generation, British Columbia	Natural gas-fired combined cycle	2002	275	275	Electricity purchase agreement (EPA)	2026
York, Ontario	Natural gas-fired simple cycle	2012	462	231	Energy supply contract with IESO	2035
York BESS, Ontario	Battery energy storage system	2025	120	120	Energy supply contract with IESO	2047
East Windsor, Ontario	Natural gas-fired cogeneration	2009	92	92	Energy supply contract with IESO	2040
Goreway, Ontario	Natural gas-fired combined cycle	2009	915	915	Energy supply contract with IESO	2035
Goreway BESS, Ontario	Battery energy storage system	2025	50	50	Energy supply contract with IESO	2047
150 Mile House, British Columbia	Waste heat	2008	5	5	EPA	2028
Savona, British Columbia	Waste heat	2008	5	5	EPA	2028
Canada renewables						
Quality Wind, British Columbia[2]	Wind turbine	2012	142	72	EPA	2037
Halkirk 1 Wind, Alberta	Wind turbine	2012	150	150	Merchant with RECs sold under fixed price agreement	2032 (RECs)
Halkirk 2 Wind, Alberta	Wind turbine	2025	122	122	Clean electricity supply agreement for 49% of energy	2045
Whitla Wind, Alberta	Wind turbine	2019 (Phase 1) 2021 (Phases 2 and 3)	353	353	Fixed price contract with the AESO for 202 MW PPA for 25 MW VPPA for 126 MW	2039 2036 2032
Strathmore Solar, Alberta	Solar	2022	41	41	PPA for energy and RECs	2047
Clydesdale Solar, Alberta	Solar	2022	75	75	VPPA covering 38 MW of energy and RECs VPPA covering 30 MW of energy and RECs	2037 2037
Kingsbridge 1 Wind, Ontario	Wind turbine	2001 and 2006	39	39	Energy supply contract with IESO	2027

Facilities and portfolio optimization

Facility category and facility	Type of facility	Year commissioned	Net generation capacity (MW) Facility	Capital Power interest	Revenues based on	Contract expiry
Port Dover and Nanticoke Wind, Ontario[2]	Wind turbine	2013	105	54	Energy supply contract with IESO	2033
U.S. flexible generation						
Decatur Energy, Alabama	Natural gas-fired combined cycle	2002	885	885	Tolling agreement	2032
Arlington Valley, Arizona[3]	Natural gas-fired combined cycle	2002	600	600	Tolling agreement and heat rate call option	2038
Midland Cogeneration, Michigan	Natural gas-fired combined cycle	1990	1,633	817	PPA, Steam and EPA	2040 and 2035
Frederickson 1, Washington	Natural gas-fired combined cycle	2002	265	133	Tolling agreement	2030
Harquahala, Arizona[4]	Natural gas-fired combined cycle	2004	1,092	546	Tolling agreement	2031
La Paloma, California[4]	Natural gas-fired combined cycle	2003	1,062	1,062	Merchant and resource adequacy contracts	2029
Hummel Station, Pennsylvania[5]	Natural gas-fired combined cycle	2018	1,124	1,124	Merchant and capacity payments	–
Rolling Hills, Ohio[5]	Natural gas-fired simple cycle	2003	1,023	1,023	Merchant and capacity payments	–
U.S. renewables						
Beaufort Solar, North Carolina	Solar	2015	15	15	PPA	2030
Bloom Wind, Kansas	Wind turbine	2017	178	178	Fixed price contract	2027
Macho Springs Wind, New Mexico	Wind turbine	2011	50	50	PPA	2031
New Frontier Wind, North Dakota	Wind turbine	2018	99	99	Fixed price contract	2030
Cardinal Point Wind, Illinois	Wind turbine	2020	150	150	Fixed price contract	2032
Buckthorn Wind, Texas	Wind turbine	2018	101	101	Offtake arrangements	2031 and 2038

1 For operational reporting, Genesee 1, 2 and 3 are combined as a single facility referred to as Genesee Generating Station. Genesee Unit 1 was originally commissioned in 1994 and Genesee Unit 2 was originally commissioned in 1989. Both units were repowered and commissioned in December 2024. The generating capacities of Units 1, 2 and 3 are 666 MW, 666 MW and 525 MW, respectively. However, there is currently a system limit in place, called the MSSC, that sets the maximum amount of supply loss the Alberta grid can reliably withstand when operating in an interconnected (466 MW limit) or islanded condition (425 MW limit). This means generation from each of Units 1, 2 and 3 is currently limited to a maximum of 466 MW or 425 MW, as applicable. The Company is exploring, with the AESO, ways to enable an increase to the generating output of each facility above the MSSC.

2 On December 20, 2024, Quality Wind and Port Dover and Nanticoke Wind ownership interests were sold down.

3 In January 2026, Capital Power extended its summer tolling agreement for Arlington Valley to 2038 (see Subsequent Events).

4 La Paloma and Harquahala were acquired in February 2024.

5 Hummel Station and Rolling Hills were acquired in June 2025 (see Significant Events).

Facilities and portfolio optimization

Facility category and facility	Type of facility	Year to be commissioned	Net generation capacity (MW) Facility	Net generation capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Under construction or in advanced development						
Maple Leaf Solar	Solar	2027	73	73	PPA	2052
Bear Branch Solar	Solar	2026	35	35	PPA	2051
Hornet Solar	Solar	2026	73	73	PPA	2051
East Windsor Expansion	Natural gas-fired simple cycle	2026	106	106	Energy supply contract with IESO	2040

Portfolio optimization and U.S. trading

Capital Power's commodity portfolio is comprised of generation assets, customer positions and trading positions. All commodity risk management and optimization activities are centrally managed by Capital Power's commodity trading group. Portfolio optimization includes activities undertaken to manage our exposure to commodity risk and enhance earnings. Overall commodity exposure within the portfolio is managed within limits established under our risk management policies.

Capital Power manages output from our merchant and contracted facilities with residual commodity exposure on a portfolio basis. Capital Power sells and/or buys physical and/or financial forward contracts that are non-unit specific, to reduce exposure to facility specific availabilities. Capital Power also takes positions in markets outside of core markets to reduce exposure, develop capability to support our growth strategy and to generate trading profits.

Consolidated net income and results of operations

The primary factors contributing to the change in consolidated net income for 2025 compared with 2024 are presented below followed by further discussion of these items.

($ millions)

Consolidated net income for the year ended December 31, 2024		**701**
Increase (decrease) in adjusted EBITDA[1]:		
Canada flexible generation	12	
Canada renewables	(43)	
U.S. flexible generation	221	
U.S. renewables	1	
Corporate	46	237
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(580)
Increase in depreciation and amortization expense		(77)
Decrease in impairments		27
Change in foreign exchange gains or losses		50
Increase in net finance expense and depreciation from equity-accounted investments		(27)
Increase in net finance expense		(86)
Decrease in loss on disposals and other transactions		21
Increase in acquisition and integration costs		(31)
Decrease in gain on divestiture		(309)
Other		43
Decrease in income before tax		(732)
Decrease in income tax expense		190
Decrease in net income		**(542)**
Consolidated net income for the year ended December 31, 2025		**159**

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

Consolidated net income and results of operations

Results by segment and other

	Year ended December 31,							
	2025	2024	**2025**	2024	**2025**	2024	**2025**	2024
	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	44,616	37,821	91	92	2,789	2,283		
Canada flexible generation	18,721	15,976	93	90	2,181	2,193	741	729
Canada renewables[6]	2,252	2,617	95	96	111	214	111	154
Total Canada	**20,973**	**18,593**	**93**	**91**	**2,292**	**2,407**	**852**	**883**
U.S. flexible generation	21,670	17,139	90	91	1,416	757	775	554
U.S. renewables	1,973	2,089	90	93	146	146	103	102
Total U.S.	**23,643**	**19,228**	**90**	**92**	**1,562**	**903**	**878**	**656**
Corporate[7]					40	19	(150)	(196)
Unrealized changes in fair value of commodity derivatives and emission credits					(174)	447		
Consolidated revenues and other income and adjusted EBITDA					**3,720**	**3,776**	**1,580**	**1,343**

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 $546 million and $227 million for the year ended December 31, 2025, respectively, compared with $439 million and $199 million for the year ended December 31, 2024, respectively.
6 Quality Wind and Port Dover and Nanticoke Wind were partially divested on December 20, 2024. Revenues and other income and adjusted EBITDA are included up until December 20, 2024, for Capital Power's full ownership.
7 Corporate revenues are partially offset by interplant category eliminations.

Average power and natural gas energy pricing

	Year ended December 31,	
	2025	2024
Average power prices		
PJM – Western Hub (US$/MWh)[1]	**50.20**	N/A
PJM – AEP Dayton Hub (US$/MWh)[1]	**45.69**	N/A
PJM realized power price average (US$/MWh)[1,2]	**42.93**	N/A
Alberta AESO ($/MWh)	**43.67**	62.78
Alberta realized power price average ($/MWh)[2]	**74.11**	79.04
CAISO SP15 (US$/MWh)	**31.86**	32.60
California realized power price average (US$/MWh)[2]	**106.19**	83.04
Average natural gas prices		
PJM – Transco Leidy (US$/MMBtu)[1]	**2.58**	N/A
PJM – Tetco ELA (US$/MMBtu)[1]	**3.08**	N/A
Alberta AECO ($/GJ)	**1.61**	1.29
SoCal Border (US$/MMBtu)	**2.77**	2.11

1 Pricing for the year ended December 31, 2025 is from the date of acquisition of Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events).
2 Realized power price is the average aggregate price realized through selling power generation into the spot market, the Company's commercial contracted sales and portfolio optimization activities. When long-term forward portfolio optimization hedges are transacted, they reflect the market's expectations for future period pricing. Ultimately, spot pricing may vary from expected forward pricing due to a number of factors resulting in realized power prices in a given period that can differ materially from spot pricing.

Consolidated net income and results of operations

Canada flexible generation

Alberta spot power price averaged $44 per MWh for the year ended December 31, 2025, compared to $63 per MWh in the prior year. Mild temperatures across the province throughout the majority of the period and improved thermal supply resulted in lower Alberta settled and captured pricing by our Alberta portfolio year-over-year.

Generation for the year ended December 31, 2025 increased compared to the same periods in the previous year while availability remained consistent due to the following net effect:

- increased generation at Genesee Generation Station due to incremental capacity gained from the repowering of units 1 & 2 which achieved commercial operations in the fourth quarter of 2024,
- increased availability and generation year-over-year at Goreway due to tighter market conditions with increased demand and more extreme weather in 2025 compared to 2024, and
- partially offset by lower dispatch and generation at Clover Bar Energy Centre and Shepard due to lower year-over-year power pricing.

Lower revenues and other income for the year ended December 31, 2025, compared to the same period in 2024 were primarily due to reduced power pricing realized by the Alberta portfolio slightly offset by higher generation as listed above and increased revenues from the Ontario BESS projects which achieved commercial operations in September 2025.

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

Canada renewables

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

U.S. flexible generation

Generation for the year ended December 31, 2025 increased compared to December 31, 2024 due to the following net effect:

- acquisition of the Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events),
- the impact of higher fuel costs on MCV's position in the merit curve, resulting in lower dispatch, and
- lower generation for La Paloma and Harquahala resulting from the impact of higher fuel costs and a planned outage at La Paloma in 2025, partially offset by a full year of generation in 2025 at both facilities which were acquired in February 2024.

Year-to-date availability is consistent compared to last year and is impacted by standard fall maintenance outages.

Revenues and other income for the year ended December 31, 2025 was higher than the prior year due to the acquisition of Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events), a full year of revenue for La Paloma, higher realized power price at La Paloma and Arlington Valley due to the impact of our hedging program, and the foreign currency translation impact of a stronger U.S. currency.

Adjusted EBITDA for the year ended December 31, 2025 was higher than the prior year due to the same factors as the increase in revenue described previously, and a full year of earnings for Harquahala, partially offset by a contracted reduction in the MCV power purchase capacity rate.

U.S. renewables

The results of U.S. renewables remained relatively stable year-over-year.

Corporate

Corporate results include: (i) costs of support services such as treasury, finance, internal audit, legal, people services, enterprise risk management (ERM), 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 year ended December 31, 2025, were higher compared to the same period in 2024, primarily due to insurance proceeds and higher government grant revenues recognized in 2025. Adjusted EBITDA for the year ended December 31, 2025 was higher than the same period in 2024 primarily due to the revenue impacts previously discussed, lower salary costs, net of increased contractor costs, that resulted from a reorganization late in 2024, and lower share-based compensation in 2025 due to increased valuations in 2024.

Consolidated net income and results of operations

Unrealized changes in fair value of commodity derivatives and emission credits

	Year ended December 31,			
	2025	2024	**2025**	2024
($ millions)	Revenues and other income[1]		Income before tax[1]	
Unrealized (losses) gains on Alberta power derivatives	**(216)**	268	**(215)**	266
Unrealized gains on U.S. power derivatives	**36**	181	**7**	128
Unrealized gains (losses) on natural gas derivatives	**21**	(40)	**(109)**	(153)
Unrealized (losses) gains on emission derivatives	**(15)**	38	**(8)**	22
Unrealized losses on emission credits held for trading	**–**	–	**(17)**	(25)
	(174)	447	**(342)**	238

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 year ended December 31, 2025, we recognized unrealized losses on Alberta power derivatives of $215 million mainly due to impacts of increasing forward prices on net forward sale contracts. During the comparable period in December 31, 2024, we recognized unrealized gains of $266 million mainly due to the impacts of decreasing forward prices on net forward sale contracts.

During the year ended December 31, 2025, we recognized unrealized gains on U.S. power derivatives of $7 million mainly due to decreasing forward pricing on net forward sale contracts in California and U.S. renewable facilities, partially offset by unrealized losses on contracts at Hummel Station and Rolling Hills. During the comparable period in December 31, 2024, we recognized unrealized gains of $128 million mainly due to the impact of decreased forward prices on forward sale contracts associated with the majority of the Company's U.S. renewables facilities and La Paloma.

During the year ended December 31, 2025, we recognized unrealized losses on natural gas derivatives of $109 million due to impacts of decreasing forward pricing on net forward buy contracts in the U.S. During the comparable period in December 31, 2024, we recognized unrealized losses of $153 million due to the impacts of decreased forward pricing on forward purchase contracts.

Consolidated other expenses and non-controlling interests

	Year ended December 31,	
($ millions)	**2025**	2024
Net finance expense	**(307)**	(221)
Depreciation and amortization	**(580)**	(503)
Foreign exchange gain (loss)	**21**	(29)
Loss on disposals and other transactions	**(10)**	(31)
Other items from equity-accounted investments[1]	**(150)**	(123)
Income tax expense	**(8)**	(198)
Net (loss) income attributable to non-controlling interests	**(1)**	2
Impairment	**–**	(27)
Gain on divestiture	**–**	309

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

Net finance expense

Higher net finance expense for the year ended December 31, 2025 compared with the prior year largely reflects higher interest due to the increased loans and borrowings outstanding from draws on the $600 million credit facility, $1.7 billion senior notes issued during 2025 used to fund the Hummel Station and Rolling Hills acquisition (see Significant Events) and the $450 million and $600 million notes issued during the second half of 2024 used to fund acquisitions and growth opportunities, to repay, redeem and refinance existing indebtedness, and for general corporate purposes. This was further impacted by lower capitalized interest during 2025 due to higher construction activity for the Genesee repowering project which achieved commercial operations in the fourth quarter of 2024.

Depreciation and amortization

Higher depreciation and amortization for the year ended December 31, 2025 was due to the Ontario BESS projects which were completed in the third quarter of 2025, the Goreway uprate which achieved commercial operation in the second quarter of 2025, the acquisitions of the Hummel Station and Rolling Hills facilities in the second quarter of 2025, and La Paloma in the first quarter of 2024 and the commissioning of the Genesee repowering project in the fourth quarter of 2024.

Consolidated net income and results of operations

Foreign exchange gain (loss)

The Company recognized foreign exchange gains for the year ended December 31, 2025, reflecting a decrease in the USD-to-CAD exchange rate during the period and its favourable impact on the Company's U.S. denominated debt held with Canadian entities and U.S denominated supplier financing arrangements for Canadian growth projects. Comparatively, exchange rates during the period ending December 31, 2024 were increasing resulting in foreign exchange losses.

Other items from equity-accounted investments

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

Income tax expense

Lower income tax expense for the year ended December 31, 2025, compared to the corresponding period in 2024 primarily due to lower overall consolidated net income before tax.

Impairment

During the third quarter of 2024, management made the strategic decision to redirect resources from the Company's C2CNT equity-accounted investment to other opportunities in order to better serve our customers with balanced energy solutions. Accordingly, the C2CNT equity-accounted investment was tested for impairment and an impairment of $27 million (US$20 million) was recorded.

Gain on divestiture

On December 20, 2024, Capital Power sold 49% of its interest in Quality Wind and Port Dover and Nanticoke Wind and a total gain of $309 million was recorded on this transaction in the consolidated statement of income. This gain includes $151 million related to the interest sold and $158 million upon remeasurement of Capital Power's remaining 51% interest to its fair value when control was lost.

Financial position

The following highlights changes in the consolidated statements of financial position from December 31, 2024 to December 31, 2025:

($ millions)	December 31, 2025	December 31, 2024
Assets		
Current assets	**1,542**	1,948
Non-current assets:		
Property, plant and equipment	**11,253**	8,061
Equity-accounted investments	**1,064**	1,096
Intangible assets and goodwill	**620**	744
Right-of-use assets	**136**	118
Derivative financial instruments	**373**	412
Government grants receivable	**320**	380
Deferred tax assets	**26**	26
Other assets	**107**	145
Total assets	**15,441**	12,930
Liabilities and equity		
Current liabilities	**1,635**	1,353
Non-current liabilities:		
Derivative financial instruments	**719**	494
Loans and borrowings	**6,383**	4,819
Lease liabilities	**154**	134
Deferred tax liabilities	**904**	863
Provisions	**504**	373
Deferred revenue and other liabilities	**293**	323
Total liabilities	**10,592**	8,359
Share capital	**5,036**	4,301
Deficit	**(349)**	(74)
Other reserves	**170**	349
Equity attributable to shareholders of the Company	**4,857**	4,576
Non-controlling interests	**(8)**	(5)
Total equity	**4,849**	4,571
Total liabilities and equity	**15,441**	12,930

Net working capital decreased from December 31, 2024 to December 31, 2025 by $688 million, mainly driven by:

- reduction in cash balances as described in Liquidity and Capital Resources,
- reclassifying a larger current portion of loans and borrowing from non-current due to timing of maturities,
- partially offset by deferred payments under a supplier financing arrangement on capital project costs for the construction of Halkirk 2 Wind, and
- higher income taxes recoverable due to current income tax recovery.

The Company has $1.8 billion of available liquidity from credit facilities if needed to meet obligations as they become due (2024 - $1.0 billion) (see Liquidity and Capital Resources).

Property, plant and equipment increased from December 31, 2024 to December 31, 2025, primarily due to the additions of the Hummel Station and Rolling Hills facilities in the second quarter of 2025 (see Significant Events). Intangible assets and goodwill decreased from December 31, 2024 to December 31, 2025, primarily due to amortization and the use of emissions credits for compliance purposes.

Non-current derivative financial instruments liabilities increased from December 31, 2024 to December 31, 2025 primarily driven by mark-to-market changes associated with VPPA contracts in Alberta and mark-to-market changes on the spark spread swaps for the Hummel Station and Rolling Hills facilities (see Significant Events).

Financial position

Non-current loans and borrowings increased from December 31, 2024 to December 31, 2025 due to the $1.7 billion (US$1.2 billion) of senior notes issued in the second quarter of 2025 (see Significant Events), the $600 million of unsecured senior medium-term notes issued in the fourth quarter of 2025 (see Significant Events) and draws on the syndicated credit facility, partially offset by the repayment of debt assumed on the Goreway acquisition, the $300 million redemption of medium-term notes due in 2026 and the reclassification of the current portion of loans and borrowings.

Provisions increased from December 31, 2024 to December 31, 2025 primarily due to the Federal Energy Regulatory Commission (FERC) and decommissioning provisions for the Hummel Station and Rolling Hills facilities acquired in the second quarter of 2025 (see Significant Events). Decommissioning provisions also increased due to the estimates for Bear Branch, Hornet, and Maple Leaf solar projects as construction progressed, as well as for the York and Goreway BESS facilities commissioned during 2025.

Share capital increased from December 31, 2024 to December 31, 2025 primarily due to the bought deal offering of 11,902,500 common shares and private placement of 3,455,000 common shares, at an offering price of $43.45 per common share for gross proceeds of $667 million, in the second quarter of 2025 (see Significant Events).

Liquidity and capital resources

($ millions)	Year ended December 31,		
Cash inflows (outflows)	**2025**	2024	Change
Operating activities	**962**	1,144	(182)
Investing activities	**(3,761)**	(1,916)	(1,845)
Financing activities	**2,077**	202	1,875

Operating activities

Cash flows from operating activities for the year ended December 31, 2025 were lower than the prior year, mainly due to the net impact of:

- cash outflows from changes in non-cash working capital most notably from an increase in trade and other receivables due to the clean technology income tax credit (ITC) receivables for Halkirk 2 Wind, Goreway BESS and York BESS, and increased trade receivables for Goreway related to increased revenue, partially offset by an increase in trade and other payables for La Paloma due to increased emissions liabilities, for Goreway due to increased fuel purchases and for Hornet Solar due to increased project activity. These increases in trade and other payables are partially offset by decreased capital accruals for Genesee Generating Station and Halkirk 2 Wind as the projects are completed,
- increased interest paid mainly due to increased interest on loans and borrowings due to higher debt balances,
- decreased distributions received from equity-accounted investments due to higher distributions from York Energy in the prior year related to debt refinancing, partially offset by current year distributions from Quality Wind and Port Dover and Nanticoke Wind which became equity-accounted investments due to the partial divestiture in December 2024,
- partially offset by cash inflows from the contributions of Hummel Station and Rolling Hills in June 2025 (see Significant Events), and
- lower cash taxes paid mainly due to tax depreciation and lower overall consolidated net income before tax.

Investing activities

Cash flows used in investing activities for the year ended December 31, 2025 were higher than the prior year due to the acquisitions of the Hummel Station and Rolling Hills facilities in June 2025 (see Significant Events).

Financing activities

Cash flows from financing activities for the year ended December 31, 2025 were higher than the prior year primarily due to the proceeds received from the $1.7 billion senior notes issued and increased share capital from the bought deal offering and private placement in the second quarter of 2025 (see Significant Events) along with lower repayments of loans and borrowings.

Liquidity and capital resources

Capital expenditures and investments

($ millions)	Pre-2024 actual	Year ended December 31, 2024	**Year ended December 31, 2025**	2026 estimated[1,2]	Actual or projected total[2]	Targeted completion
Repowering of Genesee 1 and 2[3]	1,053	434	**67**	10-96	1,564 to 1,650	Achieved commercial operations in the fourth quarter of 2024 and the project is substantially complete
Halkirk 2 Wind[4]	69	229	**25**	10	333	Achieved commercial operations in the fourth quarter of 2025
Ontario growth projects	19	337	**174**	61	591	York and Goreway BESS completed in the third quarter of 2025 East Windsor Expansion in the third quarter of 2026
Maple Leaf Solar	2	10	**60**	136	230	First quarter of 2027
Bear Branch Solar	6	2	**43**	55	106	Fourth quarter of 2026
Hornet Solar	6	9	**136**	54	205	Third quarter of 2026
Commercial initiatives[5]	214	54	**19**	38		
Development sites and projects	63	–	**1**	–		
Subtotal growth projects		1,075	**525**	364-450		
Sustaining – plant maintenance		162	**185**			
Total capital expenditures[6]		1,237	**710**			
Emission credits held for compliance		13	**26**			
Capitalized interest		(56)	**(40)**			
Additions of property, plant and equipment and other assets		1,194	**696**			
Change in other non-cash investing working capital and non-current liabilities		(124)	**168**			
Purchase of property, plant and equipment and other assets, net		1,070	**864**			

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 The commercial operation date required by the PPA for this project was not met. The agreement with Saputo was terminated and resulted in a termination fee of $5 million incurred in the third quarter of 2025 (see Significant Events).
5 Commercial initiatives include expected spending on various projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.
6 Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the consolidated statements of cash flows as purchase of property, plant and equipment and other assets, net.

Liquidity and capital resources

Financing activities

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

The Company's credit facilities consisted of:

		At December 31, 2025			At December 31, 2024		
($ millions)	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	Total facilities	Credit facility utilization	Available
Committed credit facilities[1]	2027 – 2030	**2,100**	**254**	**1,846**	1,000	–	1,000
Bilateral demand credit facilities	N/A	**1,402**			1,421		
Letters of credit outstanding			**604**			608	
Demand credit facilities	N/A	**25**	**–**	**25**	25	–	25
		3,527	**858**	**2,669**	2,446	608	1,838

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

In the third quarter of 2025, the Company entered into a two-year revolving credit agreement with a total commitment of $600 million, maturing in 2027 (see Significant Events). The funds can be drawn in Canadian or U.S. dollars. Interest is floating and is based on the type of draw, plus margin.

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

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

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

Rating Agency	**Rating**	**Outlook**	**Definition**
Standard and Poor's	BBB -	Stable	Exhibits adequate capacity to meet financial commitments; however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.
DBRS Limited	BBB (low)	Stable	Adequate credit quality and the capacity for the payment of financial obligations is considered acceptable but the entity may be vulnerable to future events.
Fitch Ratings[1]	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.

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

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.

Capital Power's loan and credit agreements require certain financial covenants as described below:

Financial covenant	**Required at the end of each fiscal quarter**
Modified consolidated total assets to consolidated total assets ratio[1]	Not less than 0.75 to 1.0
Consolidated senior debt to consolidated capitalization ratio[1]	Not more than 0.65 to 1.0
Consolidated EBITDA to consolidated interest expense[1,2]	Not less than 2.5 to 1.0

1 As defined in the relevant agreements.
2 Only in the event that Capital Power is assigned a rating lower than investment grade from two rating agencies: less than BBB- by S&P, BBB (low) by DBRS, and BBB- from Fitch.

As of December 31, 2025, Capital Power has met the financial covenants set out in the respective loan and credit agreements.

Liquidity and capital resources

Off-statement of financial position arrangements

At December 31, 2025, Capital Power has $604 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements, and to satisfy legislated reclamation requirements and $99 million of surety bonds issued for certain capital projects and contracts.

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

Capital resources

	As at December 31,	
($ millions)	**2025**	2024
Loans and borrowings	**6,730**	4,976
Lease liabilities[1]	**162**	151
Less cash and cash equivalents	**(119)**	(865)
Net debt	**6,773**	4,262
Share capital	**5,036**	4,301
Deficit and other reserves	**(179)**	275
Non-controlling interests	**(8)**	(5)
Total equity	**4,849**	4,571
Total capital	**11,622**	8,833

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

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

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

Contractual obligations, contingent liabilities, other legal matters and provisions

Based on available credit facilities (see Liquidity and Capital Resources), access to capital markets and expectations for future periods' financial results, Capital Power has adequate liquidity to meet our contractual obligations as follows:

	Payments due by period						
($ millions)	2026	2027	2028	2029	2030	Thereafter	Total
Loans and borrowings[1]	526	424	1,329	225	279	3,817	6,600
Interest on loans and borrowings	331	319	281	229	218	676	2,054
Trade and other payables[2]	719	–	–	–	–	–	719
Lease liabilities	17	18	18	18	17	243	331
Capital – growth projects[3]	350	66	34	–	–	–	450
Capital – commercial initiatives[4]	38	56	23	24	23	19	183
Decommissioning provisions[5]	32	15	7	–	–	1,030	1,084
Energy purchase and transportation contracts[6]	385	327	212	161	137	714	1,936
Operating and maintenance contracts	142	150	141	125	113	597	1,268
Environmental credits[7]	156	45	11	5	19	30	266
Commodity and other derivative liabilities net of financial assets	58	108	96	69	55	199	585
Total	**2,754**	**1,528**	**2,152**	**856**	**861**	**7,325**	**15,476**

1 Repayments of loans and borrowings exclude fair value differentials of $5 million related to debt assumed on previous asset acquisitions and $167 million related to repayments of tax-equity financing through non-cash tax-equity attributes.

2 Excluding accrued interest on loans and borrowings of $70 million.

3 Capital Power's obligations for capital – growth projects in future periods include Ontario growth projects and the various renewables projects listed in the Liquidity and Capital Resources section over the construction periods of those projects, as well as expected spend on other development sites and projects in 2026. These obligations exclude interest to fund construction of $24 million and refundable transmission system contribution payments.

4 Capital Power's obligations for capital – commercial initiatives in future periods include various projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

5 Capital Power's decommissioning provisions reflect the undiscounted cash flows required to settle obligations for the retirement of its generation facilities and the Genesee Mine.

6 Energy purchase and transportation contracts include natural gas transportation contracts which are based on estimates that are subject to changes in regulated rates for transportation and natural gas purchase contracts. The estimates for natural gas purchase contracts are subject to changes in expected consumption levels and have expiry terms ranging from 2026 to 2039.

7 Future environmental credit purchases are presented net of future environmental credit sales.

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.

Other legal matters

From 2017 through 2023, the GoA withheld approximately $3 million per year from the Company's annual off-coal payment, on the basis of an alleged "implied term" of the Off-Coal Agreement. Capital Power believes there was no such implied term and has therefore sued the GoA for recovery of the withheld amount and specific performance for future payments.

During the second quarter of 2025, the Company settled the disputed amounts with the GoA and received a cash payment of $10 million, which resulted in a decrease to the amount previously recorded of approximately $5 million, recorded in net income through loss on disposals and other transactions. The respective deferred revenue and government grant receivable amounts were likewise adjusted to reflect total payments over the 14-year term of $706 million. At December 31, 2025, the remaining government grants receivable balance relating to off-coal compensation from the GoA was $231 million.

Contractual obligations, contingent liabilities, other legal matters and provisions

Line Loss Rule Proceeding

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

As a result of the LLR Proceeding, Capital Power incurred additional charges related to historical periods. Net expenses of $19 million were recorded in prior years to reflect the Company's net obligation. The invoicing process resulted in gross billings to Capital Power of which those amounts not attributable to Capital Power were largely recovered from the appropriate parties, with the exception of those related to the Sundance C PPA from the Balancing Pool.

The Balancing Pool is disputing its liability to make payment for the LLR adjustment invoices related to the Sundance C PPA, which amounts to a net potential exposure to Capital Power of approximately $25 million recorded within other assets at December 31, 2025. The Company believes the various agreements governing the termination and transfer of the Sundance C PPA and related transmission agreements with the AESO had the effect of transferring all past liabilities for the Sundance C PPA to the Balancing Pool. Capital Power therefore filed a statement of claim at the Alberta Court of Queen's Bench on January 11, 2021 against the Balancing Pool, the Province of Alberta and the AESO in which it is sought, among other relief, recovery from the Balancing Pool and the Province of Alberta of all amounts Capital Power was compelled to pay to the AESO on account of the LLR adjustment invoices relating to the Sundance C PPA as well as interest and legal costs, including the portion invoiced to the Balancing Pool but not received by the Company pertaining to all tranches of invoices. Capital Power has since discontinued its claim against the AESO but continues to proceed against the Balancing Pool and the Province of Alberta. This process remains ongoing. Capital Power expects to ultimately realize the full amount of the gross receivables related to the line losses upon resolution of the dispute.

Risks and risk management

Events within and outside of Capital Power bring both risk and opportunity. Effective risk management is critical to protecting shareholder value and supporting disciplined decision-making. Risk management is embedded across the organization and supported by an ERM program aligned with the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework and the Company's ERM policy. Our Board oversees principal risks and the balance between risk and returns. Management maintains systems to identify, assess, respond to, report on, and monitor key risks, with executive risk owners accountable for response strategies and the President and CEO having ultimate accountability. Risk assessments are reported to the Board quarterly and inform the annual risk-based internal audit plan.

Key changes in 2025

Capital Power's risk profile continues to evolve as the Company advances its strategy and expands its footprint in the United States. Notable changes include:

- Increased focus on U.S. natural gas acquisition opportunities, increasing diligence, integration and execution requirements.
- Increased U.S. exposure, including entry into PJM (see Significant Events), with greater sensitivity to locational pricing, congestion, capacity-related constructs and political, geopolitical and regulatory risks.
- Increased potential for policy shifts that could affect the power sector with political change at the federal level in both Canada and the U.S. during the year.
- Continued evaluation of large-load opportunities, including data centres, with heightened reliability expectations.

Capital Power's principal risk factors could have an adverse impact on the Company's business operations and results, financial condition and strategy, ability to execute our growth strategy, or reputation. Capital Power's principal risk factors and the associated risk mitigation strategies are described below.

Growth, acquisitions and integration execution

Risk

Capital Power's strategy includes the acquisition, construction and development of power generation facilities and anticipates power demand growth in North America. These activities often require significant up-front expenditures and management focus before outcomes are known, and can introduce risks related to valuation, diligence, integration, financing and performance. Competition on acquisition and development opportunities is significant, and there can be no assurance that we will pursue or win any opportunity assessed. Growth execution may also be affected by changes in government policy, lower than anticipated demand growth, permitting, access to transmission, supply chain constraints, labour availability, inflation, interest rates, the ability to secure offtake or other commercial arrangements or other matters beyond the Company's control.

Potential impacts

Potential impacts include, but are not limited to, delays, cost overruns, reduced returns, impairment, integration disruption, and underperformance relative to expectations.

Key mitigation strategies:

- Governance over major investments, including Board visibility on material transactions and alignment to long-term plan and strategy.
- Structured development and acquisition processes, including stage-gated screening, risk assessment, and diligence.
- Investment discipline, including periodic review of hurdle rates and valuation assumptions.
- Integration planning with defined accountabilities for operations, commercial, finance, legal, and information technology, including post-close performance monitoring.
- Commercial discipline, including evaluation of contract quality, counterparty credit, and recontracting pathways.
- Data centre opportunity screening criteria that emphasizes deliverability, reliability requirements, and risk-adjusted returns.

Market and commodity exposure basis

Risk

Capital Power is exposed to power and natural gas price volatility in the markets where the Company operates, including exposure from merchant generation and basis differentials at certain U.S. facilities. This creates both opportunity and exposure, with the Company's largest exposure in the Alberta, PJM and U.S. West power markets. Power and natural gas markets can be influenced by supply and demand, fuel availability, environmental compliance costs, market structures, competitor behaviour, transmission congestion, and weather conditions. It is not possible to predict future power or natural gas prices with certainty, and price volatility could have a material effect on Capital Power.

Capital Power uses both physical and financial derivative instruments to manage its natural gas price risk and for merchant trading activities. Capital Power could realize financial losses on these derivative instruments because of volatility in the market values of the underlying commodities and potential mismatch between purchased gas and gas required to be consumed at power plants. These activities, although primarily intended to mitigate earnings volatility, can expose Capital Power to other risks.

Risks and risk management

Capital Power's natural gas-fired facilities, a portion of which are uncontracted, are susceptible to the risks associated with the volatility of associated commodity prices. Natural gas purchases for these facilities are made under variable price contracts and facility availability or efficiency changes can add to the risks.

Capital Power manages power price risk by using a variety of physical and financial derivative instruments, including futures, forwards, options, heat rate call options, swaps, tolls and PPAs. These activities, although primarily intended to mitigate earnings volatility, can expose Capital Power to other risks. Asset unavailability can affect the long-term contracts in various ways. Generally, tolls and PPAs provide provisions for long-term outages and force majeure events.

Potential impacts

Potential impacts relating to market and commodity exposure include, but are not limited to, earnings and cash flow volatility, losses on commodity positions, increased collateral requirements, reduced margins and increased exposure during periods of market stress.

For example, selling forward power may result in losses if the assets from which that power is sold forward are unexpectedly unavailable. In addition, Capital Power enters commodity contracts to generate trading revenue, which can result in financial gains or losses. In the future, Capital Power could recognize financial losses on these contracts due to changes in their market value.

Key mitigation strategies:

- Commodity risk management governance, including defined roles, policies, limits, and regular reporting of exposures and compliance with limits.
- Portfolio approach that balances contracted merchant exposure across markets and asset types.
- Use of physical and financial instruments to manage price risk, basis risk, and margin stability, within authorized limits.
- Establish contracts with fuel cost, including carbon cost, flow-through provisions, where possible.
- Stress testing and scenario analysis of the commodity portfolio, including extreme but plausible events.
- Ongoing asset optimization to maintain competitiveness in the supply stack and protect margins.
- Active management of collateral and credit support requirements, including monitoring of liquidity headroom and counterparties.

Political

Risk

Capital Power is subject to risk associated with changing political conditions and with changes in federal, provincial, state, or local laws and regulations or common law and their interpretation by relevant authorities. Changes in government policy can affect market structures, environmental and reliability policy direction, taxation, trade and tariffs, the pace and design of infrastructure development and permitting and approvals. Political conditions may also affect energy policy direction, including the approach to climate and environmental regulation, which can influence compliance requirements, operating costs, and investment returns on generation assets.

Canada

There was a federal election in 2025, resulting in a liberal prime minister taking office in March 2025. The government may move forward with several existing policies that have the potential to impact Capital Power's strategic plans, operations and financial performance. This includes, but is not limited to, the Clean Energy Regulations (CER), Greenwashing Provisions, Mandatory Climate Disclosures, the proposed Oil and Gas Emissions Cap and Canada's 2030 National Biodiversity Strategy. Capital Power will continue to monitor developments and engage with the new government to seek to mitigate the impact in these areas.

On November 27, 2025 the Government of Canada (GoC) and GoA entered into a MOU focused on strengthened energy collaboration, including commitments related to consultation and implementation approaches for federal measures that may impact Alberta industry, and signaling potential changes intended to reduce investment uncertainty (see Regulatory and Government Matters).

United States

Capital Power operates in multiple jurisdictions, each governed by distinct federal, provincial, and state policy, regulatory and market frameworks. These frameworks, including those related to the net-zero transition, may differ in timing, design and implementation, with varying implications for costs, pricing and affordability.

In the U.S., a new administration began in January 2025 resulting in a number of key developments.

The U.S. administration has imposed tariffs on imported goods from many countries, including Canada, and has indicated its intention to impose new tariffs. These tariffs, and any retaliatory measures by affected trading partners, remain uncertain and continue to evolve. Such measures may increase the cost of materials and equipment needed for our facilities, potentially affecting our profitability and the timely execution of our projects.

Risks and risk management

Tariffs and retaliatory actions may also dampen or amplify the effect of other risk factors disclosed herein, including risks relating to interest rates, currency exchange, supply chain, inflation, regulatory and government policy changes, and commodity price changes, including natural gas. Demand for power may also be impacted by general macroeconomic conditions, which could worsen as a result of the imposition of new, additional or changes to pre-existing tariffs and other trade restrictions or other similar measures. These risks may lead to decreased revenues or increased costs for us, either of which could have a material adverse effect on Capital Power's financial condition and/or results of operations.

Separately, under the Canada United States Mexico Agreement, the parties are scheduled to meet for the first joint review on July 1, 2026. While at this time we do not expect significant impacts to Capital Power, this is an evolving risk that may impact future supply chain costs and sales of electricity from Canada to the U.S.

In California and certain other states, climate disclosure laws have been enacted that, once implemented through regulation, would require certain entities that do business in these states and exceed specified revenue thresholds to publicly report GHG emissions, including Scope 1 and Scope 2 emissions initially and Scope 3 emissions in subsequent years. Based on the Company's operations, we do not expect to be subject to these requirements; however, applicability could change in the future depending on the Company's revenue profile and activities in California. Management will continue to monitor developments.

In addition, as the Company expands in the U.S. wholesale markets, including PJM (see Significant Events), additional opportunities are created, as are risk exposures from changes in market design, reliability requirements, transmission conditions, congestions and other rule changes that can affect dispatch economics and revenues. Changes to market designs are occurring to address the evolving mix of generation on the grid and to send appropriate price signals so that system operators have access to the attributes necessary to reliably operate the grid.

The current U.S. administration has signaled that there will be few new decarbonization requirements at the federal level, and aggressive state-level decarbonization requirements will likely be subject to significant legal challenges in the future.

Potential impacts

Political developments could result in changes to market rules, permitting timelines, reliability and environmental requirements, trade and tariff measures, taxation and infrastructure investment priorities. These changes could impact profitability or capital costs, delay projects, affect commodity market outcomes and contracted conditions, or reduce the expected returns on generation assets.

Key mitigation strategies:

- Monitor political and policy developments across jurisdictions and assess potential impacts on strategy, markets, and project execution.
- Engage constructively with governments, regulators, system operators, and industry associations to support feasible, reliable and affordable policy outcomes.
- Maintain diversification across geographies and technologies to reduce exposure to any single jurisdiction or policy pathway.
- Incorporate change-in-law provisions in material contracts where possible.
- Maintain disciplined capital allocation and scenario analysis that considers multiple policy and market outcomes.
- Maintain compliance and governance process that support timely response to evolving requirements and expectations.

Asset performance, operational reliability and transmission

Risk

Generation performance depends on the reliability of our assets, and availability of fuel (natural gas, wind or solar) and other inputs, and the ability to reliably deliver natural gas and electricity to and from facilities. Unplanned outages, prolonged maintenance events, equipment failure, inadequate transmission capacity, or inadequate fuel supply can have a significant effect on Capital Power's revenues, costs and contract performance.

Capital Power's natural gas facilities depend on pipeline infrastructure owned and operated by external parties to deliver fuel. Inadequate pipeline capacity, curtailment, operational disruptions, constraints on firm transportation or other limitations in the natural gas delivery system could restrict fuel supply to facilities or increase fuel costs, which could reduce generation and impact contract performance.

Capital Power depends on transmission infrastructure owned and operated by external parties to deliver wholesale power from its generation facilities. Transmission system limitations, congestion, curtailment, interconnection constraints, or regulatory barriers can restrict the Company's ability to deliver electricity to customers and markets even when facilities are operating. Where transmission is constrained, realized pricing may also be negatively affected through increased basis differentials.

Capital Power procures goods and services from a diverse range of suppliers, spanning local to international markets. International trade policies, tariffs, sanctions, or other geopolitical events could increase procurement costs, extend lead times, restrict availability of critical components, or reduce access to specialized services. These impacts could delay maintenance and repairs, extend outage durations, affect construction schedules, and increase operating and capital costs. In addition, counterparties to PPAs have remedies available to them if Capital Power fails to operate facilities in accordance with contract requirements, including the recovery of damages and termination of contractual arrangements. PPAs expire at various times and there can be no assurance that a subsequent PPA will be available or, if available, that it will be on terms, or at prices that permit the operation of the facility on a profitable basis.

Risks and risk management

Potential impacts

Potential impacts include, but are not limited to, reduced availability and delivered generation, higher costs, contractual penalties, reduced capacity, increased basis and congestion exposure, reduced ability to attract large-load opportunities like data centres, delayed capital projects and decreased profitability.

Key mitigation strategies:

- Preventative maintenance and operating standards designed to support reliability and availability across the fleet.
- Long-term service agreements and constructive original equipment manufacturer (OEM) relationships on key assets, including access to replacement components and technical support.
- Inventory management of critical spares and proactive procurement for long lead-time parts.
- Root cause analysis and fleet-wide sharing of learning to reduce recurrence of failures.
- Comprehensive fleet-wide emergency and contingency plans with annual tabletop exercises for continuous improvement.
- Firm natural gas transportation contracts where warranted to ensure the delivery of natural gas.
- Due diligence on transmission and fuel transportation adequacy for acquisitions and major investments.
- Insurance programs intended to reduce the financial impact of insured events, recognizing deductibles, limits and exclusions.

Cyber-security and technology

Risk

Capital Power relies on information technology and operational technology systems to operate facilities, manage energy marketing activities, and conduct corporate processes. Cyber threats - whether targeting the Company directly or through its supply chain - could result in operational disruption, loss or misuse of sensitive information, physical impacts to assets, regulatory penalties, and reputational damage. Increased use technology, including AI tools, can introduce additional data privacy and security risk considerations if not appropriately governed.

Capital Power maintains a flexible work arrangement incorporating a hybrid model of working from home and in the office for non-plant staff. Having a hybrid workforce increases the number of access points thereby increasing the possibility of certain cyber threats, such as increased malicious network traffic and physical vulnerabilities. Capital Power continues to evolve the security of our systems, both physical and virtual, through measures such as secure remote access with multifactor authentication, remote patching and deployment of malware updates and a cyber-security training and awareness program.

Potential impacts

Potential impacts include, but are not limited to, operational disruption, financial loss, regulatory non-compliance, data compromise and reputational harm.

Key mitigation strategies:

- Cybersecurity governance and oversight. Examples include the Cyber Security Leadership Council, comprised of senior leaders from various areas of Capital Power which meets regularly to monitor effectiveness of the strategies below and address new and evolving risks.
- Security controls across identity and access management, monitoring, incident response, backup and disaster recovery.
- Mandatory corporate-wide training and awareness programs designed to reduce social engineering, phishing and AI risk.
- Testing and assurance activities, including penetration testing and periodic independent assessments.
- Supplier and third-party risk management practices, including supply chain cyber risk measures.
- External audits, assessments and annual penetration testing.
- Compliance with North American Electric Reliability Corporation Critical Infrastructure Protection standards, based on each respective asset's categorization and the applicable regulatory region's requirements.

Climate change

Risk

Climate change, along with reliability and affordability, will continue to be primary themes driving the industry in which Capital Power operates for the foreseeable future. Climate change and the energy transition continue to affect power markets, policy, environmental regulation and customer and investor expectations, which may affect compliance costs and the competitiveness of certain assets. Physical risks, including more frequent or severe extreme weather events, can disrupt operations and supply chains and affect reliability and market prices. Insurance market conditions may also change as physical risks evolve.

Risks and risk management

Capital Power's portfolio of assets includes a diversity of fuel types, including flexible-generation facilities in Canada and the U.S. Decarbonization trends therefore create risks, particularly around carbon price and policy which may result in higher compliance obligations and reduced margins for our flexible-generation fleet. Carbon pricing is a central mechanism of climate policy in Canada, compared to the U.S. where it has been adopted in certain states and regions and will be priced in more indirectly or otherwise addressed through higher carbon air regulation for the foreseeable future. Government policy impacts how and the extent to which thermal generation may operate, and Capital Power actively engages with regulatory bodies to ensure the transition to lower-emitting power generation is feasible and aligned with operational realities.

Recent actions by the U.S. federal administration have signaled a shift in federal climate and energy policies, including the potential rollback of existing climate-related policies, regulations and initiatives, such as the Inflation Reduction Act. A variety of federal, state and local government agencies provide incentives to promote electricity generation from renewable sources. These incentives are in the form of rebates, tax credits and other financial incentives which help to motivate end users, distributors, system integrators and others to install renewable energy powered generating systems. Any changes to reduce, shorten or eliminate the scope and availability of these incentive programs could materially and adversely impact its related planned investments in renewable energy projects in the U.S.

Potential impacts

Potential impacts include, but are not limited to, higher compliance costs, reduced margins for certain assets, increased capital requirements, operation disruption, insurance availability and reputational harm.

Strategies employed for managing climate change risk:

- Strategic planning that considers a range of decarbonization pathways, market conditions and policy outcomes.
- Advancing our decarbonization efforts through the completion of our Genesee Repowering and Ontario BESS projects, advancing our joint SMR feasibility study, and continuing to develop our pipeline of renewables.
- Monitoring and pursuing feasibility studies in promising low-carbon technologies such as Carbon Capture and Storage (CCS) and SMRs.
- Ongoing commercial initiatives intended to improve reliability, efficiency and emissions performance where applicable.
- Regular engagement with government bodies to participate in the development of carbon and other environmental policy.
- Compliance cost management via an active presence in environmental commodity markets.
- Monitoring the insurance market for material changes to insurance policies that may affect the Company's ability to seek coverage for high-risk assets.

In addition to risk, decarbonization trends also create significant opportunities for power generation, as demonstrated by the Company's ongoing efforts to explore new technologies such as SMRs. Capital Power has integrated sustainability into our corporate strategy and long-term planning process to monitor these trends and assess opportunities to ensure resilience of our strategy.

People

Risk

Capital Power's ability to operate safely and reliably and to execute its strategy depends on attracting and retaining skilled employees and maintaining effective labour relations. Workforce changes, retirements and organizational shifts can increase the risk of losing critical skills and institutional knowledge. Operations and construction environments can be affected by stakeholder concerns, activism, and evolving expectations regarding Indigenous partnership and reconciliations. Reputation risk can be a consequence of other risks and events.

Potential impacts

Potential impacts include, but are not limited to, reduced operational effectiveness, labour disruption, higher costs, health and safety incidents, delays to projects and reputational harm.

Key mitigation strategies:

- Workforce and succession planning.
- Competitive total rewards, engagement monitoring, and talent management practices to support attraction and retention.
- Labour relations practices intended to support constructive bargaining and continuity of operations.
- Safety management systems, audits and contractor alignment to safety expectations.
- Early and consistent stakeholder engagement with documented commitments, follow-through, and continuous improvement.
- Indigenous relations policies and plans focused on relationship-building and participation in economic opportunities where appropriate.

Risks and risk management

Regulatory, legal and compliance

Capital Power operates across multiple jurisdictions and is subject to extensive laws, regulations, permits and market rules. Changes in policy, regulation, or interpretation may affect project approvals, operating requirements, compliance costs, market dynamics and investment returns. The Company may also be subject to audits, inquiries and legal proceedings in the normal course of business. Tax rules and interpretations can change and tax filings may be subject to review by authorities. instruments, there could be an adverse impact on the effectiveness and cost of those projects or operations.

Certain environmental rules and regulations can impose a liability for costs to investigate or address any obligations, including but not limited to requirements relating to minimizing impact to wildlife at its wind facilities, or changes to design of competitive wholesale electricity markets in the jurisdictions in which Capital Power operates. For example, in August 2025, the AESO released the final high-level design for its restructured energy market (REM), including higher price caps. Compliance with new regulatory requirements may require the Company to incur capital expenditures, additional operating expenses or cause operations at certain facilities to end prior to the end of their economic life; failure to comply with such regulations could result in fines, penalties or the curtailment of operations. Further, there can be no assurance that compliance with or changes to environmental regulations will not materially adversely impact its business prospects, financial condition, or operations.

Potential impacts

Potential impacts include, but are not limited to, higher operating or capital costs, fines or penalties, delays, adverse outcomes in disputes, increased tax expense and reputational harm.

Key mitigation strategies:

- Compliance programs and monitoring designed to support adherence to laws, permits, and regulatory requirements across jurisdictions.
- Proactive identification of regulatory developments and participation in relevant consultation processes.
- Perform regulatory compliance audits and take corrective actions as necessary.
- Establish constructive relationships with relevant levels of government, agencies and stakeholders.
- Permitting and licensing management, including timely renewals and controls over compliance obligations.
- Environmental compliance practices for air, water, waste, remediation and wildlife requirements as applicable to the fleet.
- Use of contractual protections where feasible, including change-in-law provisions.
- Maintain a mix of technologies and geographies across its fleet.
- Internal and external expertise to support tax compliance, planning, and audit readiness.

Credit rating, liquidity, interest rate and counterparty

Capital Power's ability to fund capital and working capital requirements, depends on continued access to financial markets. Uncertainty and volatility in the Canadian and U.S. financial markets may adversely affect Capital Power's ability to obtain financing on favourable terms. Capital Power's cost of capital is influenced by prevailing market conditions, and for sustainability-linked credit facilities, by achievement of Scope 1 CO_2 emissions intensity targets that directly affect interest rates. Access to capital is also dependent upon our business and Environmental, Social and Governance (ESG) profile, as reflected in corporate credit and ESG ratings. See Liquidity and capital resources.

The ongoing volatility in financial markets driven by inflation and a fluctuating interest rate environment as well as changing political and regulatory climates in Canada and the U.S. could create additional uncertainty when accessing capital. If Capital Power is unable to access sufficient capital on acceptable terms, there could be an adverse effect on its business plan and financial condition. Additionally, Capital Power is exposed to changes in interest rates on its cash and cash equivalents, and floating rate current and non-current loans and borrowings. Interest rate risk arises from the possibility that changes in interest rates will affect future cash flows or fair values of financial instruments. Capital Power's Audit Committee of the Board of Directors, in its oversight role, monitors the assessment of financial risk management controls and procedures to ensure compliance with applicable policies, including the Company's financial exposure management policy. Additional strategies employed to manage finance risk are outlined below.

Strategies employed for managing credit rating risk:

- Maintain constructive relationships with credit rating agencies.
- Develop flexible financial structuring to adapt if circumstances would cause a credit rating downgrade from investment grade.
- Manage overall debt levels within credit metric guidelines and financial covenants.

When Capital Power uses financial instruments to sell or purchase power and/or natural gas forward, it may be required to post significant amounts of cash collateral or other credit support such as letters of credit to its counterparties.

Risks and risk management

Strategies employed for managing liquidity and interest rate risk:

- Monitor cash and currency requirements on a regular basis by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements.
- Monitor levels of other credit support required on a regular basis.
- Laddered debt maturities to avoid large debt repayments in a single year.
- Maintain constructive relationships with banks, investment banks and other financial counterparties.
- Meet financing requirements through a combination of committed and demand revolving credit facilities, financings in public and private capital debt markets, and equity offerings.
- Balance the use of fixed rate and floating rate financing options.
- Use of financial instruments to manage interest rate risks.

Counterparty risk is the possibility of financial loss associated with the inability of counterparties to satisfy their contractual obligations to Capital Power, including payment and performance. Capital Power is also dependent upon its cogeneration hosts and suppliers of fuel to its plants. If a wholesale electricity market counterparty defaults, Capital Power may not be able to replace such counterparty to effectively manage short or long energy positions, resulting in reduced revenues or increased power costs. Furthermore, a prolonged deterioration in economic conditions could increase the foregoing risks.

Strategies employed for managing counterparty credit risk:

- Maintain a credit policy including limits for credit risk exposure levels.
- Enter arrangements largely with creditworthy counterparties.
- Monitor existing counterparties' credit ratings for changes on an ongoing basis and conduct periodic credit reviews.
- Use credit enhancements such as cash deposits, prepayments, parent company guarantees, bank letters of credit, master netting agreements, margin accounts and credit derivatives.
- Monitor and report credit risk exposures.

Foreign exchange

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar affect Capital Power's capital and operating costs, revenues and cash flows and could have an adverse impact on Capital Power's financial performance. The U.S. facility operations and the foreign-sourced equipment required for capital projects are transacted in U.S. dollars. In addition, certain indebtedness is denominated in U.S. dollars.

Strategies employed for managing foreign exchange risk:

- For the Company's facilities that have a U.S. functional currency, foreign exchange movements are largely matched within its U.S. operations and hence foreign exchange exposure is mitigated.
- Enter economic hedges on capital costs denominated in U.S. dollars to mitigate exposure.
- Use of financial instruments such as foreign currency forward and cross-currency interest rate swap contracts.
- Utilize U.S. dollar denominated borrowings and/or tax equity debt financing to finance U.S. developments.

General economic conditions, business environment and other risks

In addition to the principal risks described above, Capital Power is exposed to broader economic and business environment risks that could adversely affect operating results, cash flows, financial condition, and the execution of its strategy.

Macroeconomic conditions, including inflation, recession, and changes in interest rates may increase operating, maintenance, labour, and construction costs and could affect power demand, counterparty credit quality and access to capital. While many of the Company's offtake arrangements include inflation escalation clauses, there is a risk that escalation mechanisms may not fully offset cost increases.

The Company relies on cash dividends, distributions or other transfers from its subsidiaries, including CPLP, in order to repay any debt the Company may incur, to make dividend payments to its shareholders and to meet other corporate obligations. The right of the Company, as a unitholder or shareholder of these entities, to realize on the assets of these entities in the event of their bankruptcy or insolvency, would be subordinate to the rights of their creditors and claimants preferred by statute. The terms of the credit facilities of the Company's subsidiaries prohibit them from making distributions if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution. As of December 31, 2025, the Company loaned $4,326 million to the respective subsidiaries under subordinated debt agreements. The terms of these agreements allow interest to be deferred. If interest is deferred, then CPLP has covenanted not to make distributions on any of its outstanding common limited partnership units.

Risks and risk management

The Company relies on operational and financial partnerships to grow its fleet. Failure to negotiate favourable terms with financial partners, particularly tax equity partners, could have an impact on the Company's ability to successfully execute its growth strategy. Some of Capital Power's assets are operated through joint arrangements under which Capital Power is not the operator of the associated assets. There is a risk that the assets will not be operated in accordance with Capital Power's expectations or requirements which could result in financial loss to the Company. While contractual agreements help minimize risk, there can be no assurance that such operations will continue to be effective. Capital Power is also dependent on and impacted by others in the power space, including dispatch by other generators, and transmission and distribution organizations.

Capital Power relies on contracted cash flows to maintain its investment grade credit rating and provide a stable and growing dividend to its shareholders. The Company focuses its growth on strategically positioned contracted assets that have a high likelihood to be re-contracted. To further minimize the risk of its contracted assets becoming merchant facilities post existing contracts, the Company establishes and maintains constructive relationships with contract counterparties, engages in early contract renewal discussions where possible, and deploys asset optimization initiatives to increase the competitiveness of its assets.

In the normal course of Capital Power's operations, the Company may become involved in various legal proceedings including arbitration of the interpretation of any contract. The outcome with respect to outstanding, pending, or future proceedings cannot be predicted with certainty. However, the Company does not believe that the outcome of any claims or potential claims of which it is aware, which have not already been provided for, will have a material adverse effect on Capital Power's financial condition and results of operations (see Contractual obligations, contingent liabilities, other legal matters and provisions).

Capital Power's property, boiler and machinery, business interruption and liability insurance coverages are established and maintained to minimize financial exposures associated with extreme weather and other events. The insurance coverages are subject to deductibles, limits, and exclusions, and may not provide sufficient coverage for these and other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis or that all events that could give rise to a loss or liability are insurable.

The various risks noted within this Risks and risk management section may be compounded by the level of exposure to a given geographic area, regulatory environment, or technology. The Company continues to mitigate these risks through its development and acquisition activities. These activities have allowed the Company to reduce its proportionate exposure to Alberta, while expanding its footprint in Ontario and the U.S. These activities have also resulted in an increase to the Company's proportionate investment in renewables and flexible-generation assets compared to coal assets, as Capital Power successfully transitioned the Genesee Generating Station to 100% natural gas during 2024 as well as an increase in contracted cash flows. Diversifying the Company's portfolio can result in the Company entering new markets which can bring new uncertainties which the Company mitigates as described above under strategies employed for managing growth execution risk.

There can be no assurance that any risk management steps taken by Capital Power with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

Environmental matters

Capital Power recorded decommissioning provisions of $443 million at December 31, 2025 ($346 million at December 31, 2024) for our generation facilities and the Genesee mine as it is obliged to remove the facilities at the end of their useful lives and restore the facility and mine sites to their original condition. Decommissioning provisions for the Genesee mine were incurred over time as new areas were mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could vary and the amount of decommissioning provisions could change depending on potential future changes in environmental regulations.

At December 31, 2025, Capital Power has forward contracts to purchase environmental credits totaling $1,587 million ($1,478 million at December 31, 2024) and forward contracts to sell environmental credits totaling $1,440 million in future years ($1,059 million at December 31, 2024). Included within these forward purchases and sales are net purchase amounts which will be used to comply with applicable environmental regulations and net sale amounts related to other emissions trading activities.

Regulatory and government matters

United States

U.S. Clean Air Act

Capital Power's U.S. facilities are subject to evolving federal and state air quality and greenhouse gas (GHG) requirements under the *Clean Air Act* (CAA), including National Ambient Air Quality Standards (NAAQS) and permitting obligations. Recent developments include the following:

Federal GHG regulation for fossil fuel electric generation units

In June 2025, the U.S. EPA released a draft rule that would repeal all GHG standards for fossil fuel electric generating units, effectively kicking off a rulemaking process to overturn prior requirements. If finalized, this decision, will remove the federal requirement for Capital Power to decarbonize future expansions to our thermal fleet. It is unlikely that existing gas units will face CO_2 regulation until the early- to mid-2030s at the earliest from the U.S. federal government due to the required review and planning process.

Maricopa County nonattainment and permitting matters

Capital Power's Arlington Valley and Harquahala natural gas facilities are located in Maricopa County, Arizona, which are classified as moderate nonattainment for two of the six principal pollutants under NAAQS. Reclassification to serious nonattainment levels can occur any time after February 3, 2025, which would result in changes in permitting requirements for existing, new and modified facilities. If Maricopa County continues to remain in nonattainment status, Capital Power will be challenged to construct additional turbines at Arlington Valley and Harquahala without offsetting emissions. Management continues to monitor developments.

On November 19, 2025, the U.S. EPA proposed a determination that the Phoenix–Mesa moderate ozone nonattainment area would have attained the 2015 ozone NAAQS by the applicable attainment date of August 3, 2024, if not for emissions originating outside the U.S. If finalized, the U.S. EPA's proposed determination would allow the Phoenix–Mesa area to remain classified as a moderate nonattainment area and would fulfill the Agency's statutory obligation to assess attainment by the required deadline. EPA took comments on this proposed action through December 19, 2025, and management expects the proposed decision to be sustained. This removes the overarching concern of Maricopa County being moved into a more serious nonattainment level under the CAA for the immediate future, providing more certainty on operational expectations and expansion limitations at both our Harquahala and Arlington Valley facilities.

Endangerment Finding and GHG reporting program proposals

The U.S. has proposed actions that could affect the federal framework for GHG regulation and reporting, including proposals to the Endangerment Finding and Greenhouse Gas Reporting Program. EPA issued a final rule on February 12, 2026 rescinding the 2009 Endangerment Finding, which had determined that greenhouse gases endanger public health and welfare. This action also eliminated the legal basis for regulating GHG emissions from new motor vehicles under the Clean Air Act §202(a).

This decision may face legal challenges in 2026.

The proposal to remove GHG reporting requirements is not finalized. If finalized, the proposal could remove federal reporting requirements while state-level requirements would remain in place. The 45Q CCS tax credit requires emissions reporting data to claim tax credit eligibility, so a lack of a standardized reporting system could hinder Capital Power's ability to claim federal CCS tax credits for project construction. Management is currently engaging U.S. federal officials to gain clarity on how tax credit eligibility could be impacted without a formal reporting structure in place.

Regulatory and government matters

One Big Beautiful Bill (OBBB)

In July 2025, the U.S. Congress passed a budget reconciliation bill commonly referred to as the OBBB, signed into law on July 4, 2025. The Company expects the associated tax changes to provide a benefit of approximately $200 million over the next seven years through reduced current and cash taxes from accelerated recognition of tax deductions. The OBBB also includes provisions that may reduce or restrict eligibility for certain clean energy investment tax credit and production tax credit. The OBBB introduces timing requirements, including construction commencement within one year of enactment to claim full benefits and a December 31, 2027 placed-in-service date, and sourcing requirements related to domestic content and foreign entities of concern.

Capital Power projects within the scope of this legislation include: Maple Leaf Solar, Bear Branch Solar, and Hornet Solar in North Carolina; Greencastle in Indiana; and Nolin Hills in Oregon. Management will continue to monitor and assess the implications of this legislative change on the Company's renewable growth projects.

PJM market developments, large load integration, and capacity market matters

Capital Power has merchant exposure to the PJM market through its Hummel Station and Rolling Hills facilities, which sell energy, ancillary services and capacity into PJM. PJM market is under pressure from various stakeholders including state consumer advocates, elected officials and public interest organizations to alleviate reliability and affordability concerns. If government officials at the state or federal level determine that market reform is needed to alleviate reliability and affordability concerns, then increased oversight over FERC, and by extension PJM, could facilitate or accelerate changes in market structures.

Large-load integration and interconnection frameworks

In 2025, PJM initiated a Critical Fast Path process focused on large-load additions, including a pre-process workshop held in August 2025, with the intent of developing rule changes in time to support future capacity market implementation timelines. In December 2025, FERC directed PJM to establish transparent rules to facilitate service of AI-driven data centres and other large loads co-located with generation, with an emphasis on reliability and consumer protection.

Subsequent to year-end, on January 16, 2026, PJM released a Board-directed plan to address accelerating large-load growth, including concepts such as "connect and manage" frameworks with curtailment provisions, accelerated pathways for certain generation interconnections, improved load forecasting, and a backstop procurement process for near-term reliability needs.

Capacity market developments and affordability measures

PJM's capacity market has experienced elevated clearing prices in recent auctions, including the 2027/2028 BRA clearing at the FERC-approved price collar with a cap across the PJM footprint. The auction cleared at the cap across all LDAs, including the zones relevant to Rolling Hills and Hummel, and PJM has not issued any revisions or corrections to those results.

In February 2026, PJM's Board of Managers announced its intention to extend the capacity market price collar through 2030, subject to FERC approval which is anticipated. The White House National Energy Dominance Council and governors of PJM states have formally endorsed extending the price collar as part of their "Statement of Principles Regarding PJM."

Government and stakeholder proposals regarding emergency procurement

Also on January 16, 2026, pursuant to the Statement of Principles, the White House and certain PJM-region governors publicly urged PJM to adopt emergency measures, including a one-time procurement or "emergency auction" concept intended to accelerate new generation to serve data centre driven load growth. PJM indicated it is reviewing these proposals and any material changes would be subject to PJM stakeholder processes and, where applicable, FERC review and approval.

More specifically, the Statement of Principles urged PJM to use a Reliability Backstop Auction (RBA) as a targeted reliability tool—not as a recurring substitute for the Base Residual Auction. The Statement of Principles regarding PJM defines the RBA as a new, emergency procurement mechanism designed to guarantee long-term revenue certainty for new generation when the existing PJM capacity market cannot attract enough supply. The Principles emphasize that the RBA should be narrowly scoped, used only when reliability is at risk, and paired with reforms that support new investment rather than suppressing price signals. The PJM Board has initiated a consultation on the parameters for the RBA. No final rulemaking or tariff filing by PJM has yet locked in a recurring RBA structure. Management continues to monitor these developments closely.

Carbon policy considerations

In 2019, Pennsylvania's governor signed an order for the state to join the Regional Greenhouse Gas Initiative (RGGI), a program where several states work together to reduce greenhouse gas emissions. This decision kickstarted a formal legal challenge over whether the governor alone could make this decision or if it needed approval from the state legislature. While awaiting a legal outcome in the Pennsylvania Supreme Court, the state legislature passed a funding agreement in November 2025 that prevents Pennsylvania from joining RGGI unless lawmakers specifically approve it in the future. If Pennsylvania had joined RGGI, Capital Power would have had been required to severely curtail operations at our Hummel facility. This outcome provides further market stability and operational flexibility at our existing Pennsylvania asset.

Regulatory and government matters

Canada

Budget 2025

On November 4, 2025, the GoC released Budget 2025 which includes measures intended to support investment in clean electricity and emissions reduction technologies. Key items relevant to the Company include proposal of the final implementation of the 15% Clean Electricity ITC, which may include a domestic content requirement that will be engaged upon in 2026. The government also extended the full value of the Carbon Capture Utilization and Storage ITC by five years to 2035. The budget also announced a new Office of Digital Transformation that will lead AI and emerging technology adoption across the government. It included over $900 million over five years to build sovereign AI infrastructure and to develop MOUs that support promising AI infrastructure projects in Canada.

Management will continue to monitor and engage with the government on relevant components of Budget 2025.

Industrial carbon pricing engagement

On December 19, 2025, Environment and Climate Change Canada launched engagement on proposed changes to the federal benchmark criteria. The objective is to gather stakeholder feedback to ensure industrial carbon pricing frameworks provide effective incentives for decarbonization and clean technology investment in heavy industries. Potential changes may include expanding the scope of covered industries, lowering emissions thresholds, and revising how markets are assessed for federal compliance. Following these changes, provinces may need to adjust their systems to maintain equivalency with the federal framework. Management will coordinate with internal teams to prepare a submission ahead of the January 30, 2026 deadline.

Alberta

Canada-Alberta Memorandum of Understanding

On November 27, 2025, the GoC and Alberta signed a MOU outlining commitments intended to support electricity affordability, grid stability and investment certainty, including increasing electricity generation to meet industrial growth and AI data centre needs while targeting a net-zero electricity sector by 2050.

Key measures of the MOU relevant to Capital Power, the electricity sector, and Alberta's broader economy include a revised approach to federal carbon pricing in Alberta, including negotiation of an industrial carbon pricing agreement administered through Alberta's TIER framework with an agreement targeted by April 1, 2026. The MOU immediately suspended the Clean Electricity Regulations (CER) in Alberta, pending the new carbon pricing agreement, representing a major step in overcoming challenges to developing efficient natural gas-fired projects needed for immediate demand growth. The MOU also includes plans for expanded western interties and a joint nuclear generation strategy by January 1, 2027.

Management will continue to monitor the impact of the Canada – Alberta MOU, and will participate in engagements relevant to Capital Power, particularly in relation to industrial carbon pricing and CER.

AESO Restructured Energy Market (REM)

On August 27, 2025, the AESO released the final high-level design for REM, including adoption of locational marginal pricing (LMP) for congestion management, higher price caps, and a new real-time ramping product. Rules development is underway, with implementation expected to begin mid-2027. The Company is actively participating in consultations and will continue to monitor implications for dispatchable generation economics and congestion exposure.

Large load integration and data centres

The AESO implemented a Phase I interim 1,200 MW connection limit for large load projects, with awards in October 2025, and initiated pre-engagement on Phase II to develop a longer-term large load framework covering planning, operations, markets, tariff and reliability. While the interim connection limit restricts the scale of data centre projects, Management views data centre-driven electricity demand growth in Alberta as a positive long-term development for all power producers.

On August 27, 2025, the GoA announced that it would be developing a 2% levy on grid connected data centre investments of 75 MW or greater. This would be a levy on the investments in computer hardware and is designed to be creditable against provincial corporate income taxes (meaning once a data centre becomes profitable and pays corporate income taxes, the net burden of the levy disappears). As part of Bill 12, approved on December 9, 2025, the GoA provided more details on its proposed levy structure where the levy would be graduated. 2% on grid-dependent projects; 1% on grid-connected projects that bring additional generation; and 0% on fully self-supplied (off-grid) projects. Management continues to monitor and assess how this impacts Alberta's competitiveness in attracting data centres.

On December 8, 2025, the GoA passed Bill 8, Utilities Statutes Amendment Act. The bill creates a framework to support Alberta's approach to large data centre load growth, including new regulation making authority related to data centres to accelerate large-scale data centre development and modernize the province's electricity system in response to AI-driven power demand. The bill would allow data centres to bring their own generation, fast-tracking approvals and prioritizing grid connection for projects that self-supply power. The required transmission upgrades for these connections would be paid for by the data centres themselves, not Alberta ratepayers. The government positions this as a strategy to strengthen grid reliability and affordability while attracting major digital infrastructure investment. Bill 8 also advances the REM implementation, building on reforms passed earlier in 2025.

Regulatory and government matters

AESO transmission and tariff reforms and ancillary services developments

The AESO is consulting on (i) ISO tariff redesign: filings are expected in 2026 and 2027 and potential new rates in 2029 following the AUC review process and (ii) optimal transmission planning reforms that align to the shift to LMP and include development of financial transmission rights and changes to generator connection cost allocation. Management continues to participate in the AESO's engagement and will monitor progress across all workstreams as the redesign advances through 2026.

The AESO is also progressing design work for a potential Fast Frequency Response Plus (FFR+) product, with a formal procurement process anticipated in mid-2026. Management will continue to monitor the FFR+ program's development and remain engaged in stakeholder and regulatory processes as the initiative progresses toward implementation. Contract awards are anticipated in the third quarter of 2027.

AESO Most Severe Single Contingency

Genesee repowered units 1 and 2 simple cycle commissioned May 3, 2024 and June 28, 2024, respectively, and dual cycle commissioned November 18, 2024 and December 13, 2024, respectively. Genesee Units 1, 2 and 3 are presented together as the Genesee Generating Station. The generating capacities of Units 1, 2 and 3 are 666 MW, 666 MW and 525 MW, respectively. However, there is currently a system limit in place, called the MSSC, that sets the maximum amount of supply loss the Alberta grid can reliably withstand when operating in an interconnected (466 MW limit) or islanded condition (425 MW limit). This means generation from each of Units 1, 2 and 3 is currently limited to a maximum of 466 MW or 425 MW, as applicable. The Company is exploring, with the AESO, a technical solution to enable an increase to the generating output of each facility above the MSSC. Performance testing is underway to determine the incremental MWs achievable through this technical solution. Once performance testing is complete, implementation is contingent upon approval by the system operator.

Ontario

IESO Market Renewal Program (MRP)

Ontario transitioned to the renewed market on May 1, 2025, including LMP and a financially binding day-ahead market. Management is monitoring the impacts on its Ontario generating contracts and continues to work with the IESO to minimize any adverse outcomes. Where applicable, the Company may rely on contractual protections intended to address adverse effects resulting from market rule changes.

Provincial policy initiatives

Ontario introduced legislation and an integrated energy plan intended to support system expansion and streamline delivery of infrastructure. The Province of Ontario has also proposed additional requirements for data centre connections (including Ministerial approval) and is consulting on potential restrictions related to foreign participation in Ontario's energy sector. The Company will continue to monitor these initiatives for any implications to existing operations and future contracting opportunities.

IESO contracting and procurement

The IESO concluded its second medium-term procurement (MT2 RFP) in the spring of 2025, and the Company secured a contract extension for Kingsbridge 1 at improved pricing.

Use of judgments and estimates

In preparing our audited 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.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively.

Critical judgments in applying accounting policies

The main judgments that were used in preparing Capital Power's audited consolidated financial statements relate to:

Judgment	Management applies judgment to evaluate	Resulting conclusions
Cash generating units (CGU)	What constitutes a CGU based on the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.	CGUs were determined giving consideration to geographic proximity and shared risk exposure and risk management.
Asset impairment	Whether events or circumstances may indicate that an asset's carrying amount exceeds its recoverable amount.	No indicators were identified during 2025 that required impairment testing beyond annual testing of the East Windsor CGU which contains goodwill.
Whether an arrangement contains a lease and classification of leases	Whether a PPA or similar contract conveys the right to control the Company's property, plant and equipment in return for payment, and, if so, a lease exists. Whether substantially all the risks and rewards of ownership of property are transferred to determine if the lease is accounted for as a finance lease or, if not, the lease is accounted for as an operating lease.	Contracts that convey the right to control Capital Power's property, plant and equipment and, therefore, contain a lease: Operating leases with the Company as the lessor (substantially all the risks and rewards remain with Capital Power): ▸ Decatur Energy tolling agreement ▸ Arlington Valley tolling agreement Finance lease with the Company as the lessor (substantially all the risks and rewards are transferred): ▸ Island Generation EPA The Company is the lessee for various office, equipment and land leases.
Classification of joint arrangements	How joint arrangements structured through a separate vehicle should be classified; either as a joint venture or a joint operation.	York, Quality Wind, Port Dover and Nanticoke Wind, Midland Cogeneration, and Harquahala are accounted for as joint ventures and accounted for under the equity method. The Company's obligations are limited to their respective capital contributions to the joint arrangements, and the Company's receipts of the economic benefits of the joint arrangements are primarily from the quarterly distributions and operating management fees. As a result, there is no indication that the Company has rights to the assets or obligations for the liabilities of the joint arrangements and the investments have been classified as joint ventures. Joffre, Shepard, and Frederickson 1 are accounted for as joint operations because each of the joint operators has rights to the assets and obligations for the liabilities of the arrangements and rights to the corresponding revenues and obligations for the corresponding expenses.
Control of subsidiaries that are less than wholly-owned	Whether certain subsidiaries are controlled by the Company even though the subsidiaries are less than wholly-owned.	Since the Company has majority rights, the Genesee Mine and Macho Springs Wind facilities are consolidated and have non-controlling interests.

Use of judgments and estimates

Assumptions and estimation uncertainties

The following identifies key information about assumptions and estimation uncertainties that could have a significant risk of resulting in material adjustments:

Estimate	Impacts and assumptions subject to estimation uncertainty
Measurement of fair values	Carrying amounts for financial instruments ▸ Amounts and timing of future cash flows ▸ Future prices ▸ Future capture factors ▸ Future generation forecasts ▸ Future interest rate yield curves ▸ Volatility
	Impairment of financial and non-financial assets and liabilities ▸ Discount rates ▸ Growth rates ▸ Other cash flow assumptions, including revenues, expenses and capital expenditures ▸ Future generating capacity ▸ Contract renewals and rates adjusted for inflation ▸ Fuel mix at optimized levels
	Decommissioning and other provisions ▸ Discount rates ▸ Amount and timing of asset retirement ▸ Extent of site remediation required ▸ Future cash flows based on amount and timing of settlement of obligation ▸ Expected customer renewals for other provisions
	Purchase price allocations for financial and non-financial assets and liabilities ▸ Same fair value measurement factors and assumptions as applicable to determine carrying amounts for derivative financial instruments, impairment of financial and non-financial assets and liabilities, and decommissioning and other provisions.
Depreciation and amortization	Assets useful lives are based on the life characteristics of common assets.
Recognition of deferred tax assets and availability of future taxable income against which carry forward tax losses can be used	Deferred tax assets and income tax provisions are based on the likelihood that tax losses will be recovered from future taxable income.

Financial instruments

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

($ millions)	Fair value hierarchy level[1]	December 31, 2025 Carrying amount	December 31, 2025 Fair value	December 31, 2024 Carrying amount	December 31, 2024 Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	**119**	**119**	865	865
Trade and other receivables[2]	N/A	**736**	**736**	546	546
Government grant receivable[3]	Level 2	**406**	**389**	438	400
Fair value through profit or loss					
Derivative financial instruments[3]	See below	**655**	**655**	601	601
Fair value through other comprehensive income					
Derivative financial instruments[3]	See below	**33**	**33**	55	55
Financial liabilities:					
Amortized cost					
Trade and other payables	N/A	**789**	**789**	751	751
Loans and borrowings[3]	Level 2	**6,730**	**7,052**	4,976	5,244
Fair value through profit or loss					
Derivative financial instruments[3]	See below	**980**	**980**	621	621
Fair value through other comprehensive income					
Derivative financial instruments[3]	See below	**13**	**13**	20	20

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

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

3 Includes current and non-current portion.

Risk management and hedging activities

Capital Power is exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. We use various risk management techniques, including derivative instruments such as forward contracts, fixed-for-floating swaps, and option contracts, to reduce this exposure. These derivative instruments are recorded at fair value on the Consolidated Statements of Financial Position except for non-financial derivatives that are entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with expected purchase, sale or usage requirements.

Unrealized changes in the fair value of financial and non-financial derivatives that do not qualify for hedge accounting and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements are recognized in net income as revenues, energy purchases and fuel, foreign exchange gain or loss or net finance expense. The corresponding unrealized changes in the fair value of the associated economically hedged exposures are not recognized in income. Accordingly, derivative instruments that are recorded at fair value can produce volatility in net income as a result of fluctuating forward commodity prices, foreign exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged on an economic basis. As a result, accounting gains or losses relating to changes in fair values of derivative instruments do not necessarily represent the underlying economics of the hedging transaction.

For example, Capital Power usually has more physical supply of power from our facilities than has been contracted to physically sell. Capital Power utilizes financial sale contracts to reduce our exposure to changes in the price of power. Economically, Capital Power benefits from higher power prices due to the net long position held since our expected physical supply is in excess of our physical and financial sale contracts. An increase in forward power prices can result in fair value losses for accounting purposes whereas on an economic basis, these losses are offset by unrecognized gains on the physical supply. The economic gains will be recognized in later periods when the power is produced and sold. The opposite is true for forward price decreases in power.

Financial instruments

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

($ millions)	Fair value hierarchy level	At December 31, 2025 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)**

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

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

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

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

The change in fair values of commodity derivatives not designated as hedges is primarily due to changes in forward power, natural gas and REC prices and their impact within the Canada and U.S. flexible generation and renewables portfolios. Unrealized and realized gains and losses for fair value changes on commodity derivatives that do not qualify for hedge accounting are recorded in net income as revenues or energy purchases and fuel.

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

Disclosure controls and procedures and internal control over financial reporting

At December 31, 2025, management conducted an evaluation of the design and operation of Capital Power's disclosure controls and procedures to provide reasonable assurance that:

(i) material information relating to the Company is made known to management by others, particularly during the period in which the Company's annual filings are being prepared, and

(ii) information required to be disclosed by Capital Power in our annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The evaluation took into consideration our Disclosure Policy and internal sub-certification process, and the functioning of our Disclosure Committee. In addition, the evaluation covered our processes, systems and capabilities relating to public disclosures and the identification and communication of material information. Based on that evaluation, Capital Power's Chief Executive Officer and Chief Financial Officer have concluded that the disclosure controls and procedures are appropriately designed and effective.

At December 31, 2025, management conducted an evaluation of the design and operation of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the internal controls over financial reporting are appropriately designed and effective.

These evaluations were conducted in accordance with the Internal Control – Integrated Framework (2013), issued by the COSO of the Treadway Commission and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

In accordance with National Instrument 52-109, management's evaluation of and conclusions on the effectiveness of internal control over financial reporting did not include the internal controls of the acquired businesses of Hummel Station, LLC and Rolling Hills Generating, LLC. The financial results are included in the Company's December 31, 2025 consolidated financial statements because these entities were acquired by the Company through a business combination during the second quarter of 2025. The aggregate assets represent 18% of the Company's total assets as at December 31, 2025, and the aggregate liabilities represent 1% of the Company's total liabilities as at December 31, 2025. Gross revenue earned from the date of acquisition to December 31, 2025, represents 14% of the Company's gross revenue, and 24% for the quarter ended December 31, 2025.

Summary of quarterly results

	Three months ended							
	Dec 2025	**Sep 2025**	**Jun 2025**	**Mar 2025**	Dec 2024	Sep 2024	Jun 2024	Mar 2024
Electricity generation (GWh)								
Canada flexible generation	**4,960**	**5,029**	**3,933**	**4,799**	3,596	4,518	3,417	4,445
Canada renewables	**642**	**456**	**557**	**597**	704	541	696	676
U.S. flexible generation	**6,519**	**7,550**	**4,026**	**3,575**	4,540	5,574	3,909	3,116
U.S. renewables	**544**	**339**	**506**	**584**	568	368	581	572
Total electricity generation	**12,665**	**13,374**	**9,022**	**9,555**	9,408	11,001	8,603	8,809
Availability (%)								
Canada flexible generation	**92**	**95**	**91**	**94**	87	93	88	93
Canada renewables	**90**	**97**	**97**	**96**	96	95	97	95
U.S. flexible generation	**88**	**93**	**96**	**85**	88	96	93	94
U.S. renewables	**90**	**91**	**89**	**90**	93	88	92	92
Total average availability	**90**	**93**	**93**	**90**	89	94	91	94
Revenues and other income ($ millions)								
Canada flexible generation	**596**	**533**	**472**	**580**	523	520	473	677
Canada renewables	**30**	**23**	**28**	**30**	56	43	54	61
U.S. flexible generation	**457**	**496**	**213**	**250**	198	286	138	135
U.S. renewables	**39**	**27**	**39**	**41**	37	31	38	40
Corporate[1]	**4**	**5**	**17**	**14**	9	5	2	3
Unrealized changes in fair value of commodity derivatives and emission credits	**(48)**	**129**	**(328)**	**73**	30	145	69	203
Total revenues and other income	**1,078**	**1,213**	**441**	**988**	853	1,030	774	1,119
Adjusted EBITDA[2]								
Canada flexible generation[3]	**187**	**181**	**166**	**207**	200	187	163	179
Canada renewables[3]	**33**	**18**	**27**	**33**	42	27	41	44
U.S. flexible generation[3]	**208**	**307**	**141**	**119**	123	219	128	84
U.S. renewables	**30**	**15**	**27**	**31**	26	19	29	28
Corporate	**(44)**	**(44)**	**(39)**	**(23)**	(61)	(51)	(38)	(46)
Total adjusted EBITDA[2]	**414**	**477**	**322**	**367**	330	401	323	289

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 equity-accounted investment. Canada renewables includes 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.

Summary of quarterly results

Financial highlights

($ millions except per share amounts)	Dec 2025	Sep 2025	Jun 2025	Mar 2025	Dec 2024	Sep 2024	Jun 2024	Mar 2024
	Three months ended							
Revenues and other income	**1,078**	**1,213**	**441**	**988**	853	1,030	774	1,119
Net (loss) income	**(13)**	**153**	**(131)**	**150**	242	178	76	205
Net (loss) income attributable to shareholders of the Company	**(13)**	**154**	**(132)**	**151**	240	179	75	205
Basic (loss) earnings per share ($)	**(0.12)**	**0.94**	**(0.92)**	**1.03**	1.76	1.32	0.51	1.58
Diluted (loss) earnings per share ($)[1]	**(0.12)**	**0.94**	**(0.92)**	**1.03**	1.75	1.32	0.51	1.57
Adjusted EBITDA[2,3]	**414**	**477**	**322**	**367**	330	401	323	289
AFFO[2]	**244**	**369**	**235**	**218**	182	315	178	149
AFFO per share ($)[2]	**1.57**	**2.37**	**1.55**	**1.57**	1.38	2.42	1.37	1.21
Net cash flows from operating activities	**205**	**404**	**143**	**210**	438	236	136	334
Purchase of property, plant and equipment and other assets, net	**288**	**147**	**141**	**288**	395	231	226	218

1 Diluted (loss) 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.
3 Includes adjusted EBITDA from the York, 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 (loss) income 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 fourth quarter of 2025

Revenues and other income for the quarter ended December 31, 2025, were higher than the same period in 2024 primarily due to increased revenues from the U.S. flexible generation segment due to the Hummel Station and Rolling Hills facilities acquired in June 2025 (see Significant Events) and increased revenues from La Paloma. Revenues from Canada flexible generation were higher due to higher generation from Goreway than the same period in 2024 due to increased generation as a result of colder weather, and the York and Goreway BESS projects which achieved commercial operations in the third quarter of 2025. These increases were partially offset by losses on unrealized changes in fair value of commodity derivatives and emission credits compared to gains in the prior year.

Net loss for the quarter ended December 31, 2025, compared to net income in the comparable quarter last year due to the net impacts of:

- changes in revenues and other income described above and changes in adjusted EBITDA described below,
- a gain on divestiture in the prior year from the partial sale of Quality Wind and Port Dover and Nanticoke Wind,
- unfavourable unrealized changes in fair value of commodity derivatives and emission credits,
- increased net finance expense due to increased long term borrowings in the current year,
- higher depreciation and amortization primarily due to the acquisition of the Hummel Station and Rolling Hills facilities in the second quarter of 2025, and the commissioning of Genesee Repower 1 and 2 in the fourth quarter of 2024,
- offset by an income tax recovery during the fourth quarter of 2025 primarily due to lower overall consolidated net income before tax, compared to income tax expense in the comparable quarter last year, and
- offset by foreign exchange differences due to gains in the current year compared to losses in the prior year.

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 for the quarter ended December 31, 2025, was higher than the corresponding period in 2024 largely due to the net impact of:

- higher contributions from the U.S. flexible generation segment due to the Hummel Station and Rolling Hills facilities which were acquired in June 2025 (see Significant Events), partially offset by lower results from Midland Cogeneration due to lower revenue from a capacity rate reduction in the power purchase agreement (PPA) contract and increased fuel costs resulting in lower dispatch,
- lower corporate expenses driven by lower salary costs that resulted from a reorganization late in 2024,
- partially offset by lower contributions from the Canada flexible generation segment due to lower revenues at Clover Bar Energy Centre due to decreased generation and availability and Genesee due to lower Alberta pool prices and higher fuel costs, and lower contributions from the Canada renewables segment due to the sell down of Quality Wind and Port Dover and Nanticoke facilities in the fourth quarter of 2024.

AFFO for the quarter ended December 31, 2025, was higher than the corresponding period in 2024 primarily due to:

- higher adjusted EBITDA described above,
- current income tax recovery mainly due to tax depreciation and lower overall consolidated net income before tax,
- higher AFFO from equity-accounted investments, and
- partially offset by higher net finance expense from increased loans and borrowings and higher sustaining capital expenditures.

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							
	Dec 2025	**Sep 2025**	**Jun 2025**	**Mar 2025**	Dec 2024	Sep 2024	Jun 2024	Mar 2024
Share price ($/common share)								
High	**73.80**	**66.06**	**57.92**	**64.95**	68.73	50.88	41.99	39.43
Low	**58.23**	**54.03**	**41.87**	**44.68**	49.20	38.33	33.90	35.55
Close	**58.55**	**65.35**	**54.80**	**47.83**	63.72	49.17	38.99	38.21
Volume of shares traded (millions)	**50.4**	**43.8**	**48.7**	**59.2**	38.0	28.3	33.5	25.9

Outstanding share and partnership unit data

At February 27, 2026, the Company had 156.404 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). 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 February 27, 2026 were 157.568 million. The outstanding special limited voting shares are held by EPCOR. Subsequent to year end, the Company retired its special limited voting shares in consideration of cash payments totaling $75 million, comprised of $40 million payable in the first quarter of 2026 and $35 million payable in 2027. Concurrently, the Company entered into a 10-year agreement with the City of Edmonton which includes obligations regarding the head office.

At February 27, 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.

Forward-looking information

Forward-looking information or statements included in this IAR are provided to inform our shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes.

Forward-looking information

Forward-looking information or statements (collectively, "forward looking information") included in this IAR 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 IAR 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 IAR 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, AFFO, adjusted EBITDA, 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 (including from contracted assets) and AFFO,
- the Company's 2030 targets, including U.S. capacity, total shareholder return, AFFO per-share growth, and dividend growth,
- 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 2026 and 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 and acquisitions. This includes expectations around timing, 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,
- changes to the U.S. Clean Air Act and the resulting impact to Capital Power's decarbonization obligations in connection with future expansions to our thermal fleet,
- the performance of future projects and the performance of such projects in comparison to the market,
- the increase in outage days in 2026 expected for the Company's Canadian flexible generation portfolio,
- plans and results related to the acquisition of Hummel Station and Rolling Hills,
- re-bidding the Halkirk 2 Wind facility into future requests for proposals and the financial impact of the VPPA cancellation,
- anticipated pricing trends, growth opportunities, market conditions, and future power demand in the PJM market,
- legislative developments regarding carbon pricing in Pennsylvania and Ohio,
- power requirements and demand, future growth, and emerging opportunities (including in our existing fleet and in our merger and acquisition and development pipeline) in our target markets,
- our plans to deliver durable performance and top-tier shareholder value,
- our plans for continuing to evaluate the deployment of nuclear through 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 outcomes resulting from the MOU with Apollo Funds,
- the outcome resulting from the MOU with the data centre developer,
- the outcome resulting from the PPA with Consumers Energy for MCV and the term sheet with the co-location data centre developer,
- optimizing existing power plants and reducing overall emissions intensity,
- the anticipated benefits, outcomes, projected timing, and terms of strategic agreements, and
- the anticipated benefits of the Arlington Valley tolling agreement extension, including in respect of adjusted EBITDA.

Forward-looking information

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

- electricity and other energy (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 approval of the Michigan Public Services Commission of the PPA with Consumers Energy for MCV,
- 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 overview and Risks and Risk Management sections.

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:

- identifying and completing acquisitions contemplated by the MOU with Apollo Funds and the timing thereof, and completing documentation with Apollo Funds in respect of the contemplated investment partnership;
- completing documentation with the data centre developer in respect of the ESA, and the data centre developer's development and completion of a data centre contemplated in any 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, including in respect of the funding commitments under the MOU with Apollo Funds,
- 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.

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.

Assurance

GHD have been engaged by the management of Capital Power to undertake a limited assurance engagement, in respect of the year ended December 31, 2025, on certain quantitative performance information disclosed in Capital Power's 2025 Integrated Annual Report.

Independent practitioner's limited assurance report

Attachment 1 Verification Opinion

1. Introduction

Capital Power Corporation (CPC) retained GHD Limited (GHD) to undertake a verification of the North American Corporate Operations (Corporate Operations) Greenhouse Gas (GHG) Emission Inventory (GHG Inventory) for the period of January 1 to December 31, 2025. GHD will complete the verification in accordance with the requirements of ISO Standard *ISO 14064 Greenhouse gases - Part 3: Specification with guidance for the verification and validation of greenhouse gas statements* (ISO 14064-3:2019 or ISO 14064-3) and in general accordance with The Greenhouse Gas Protocol Corporate Accounting and Reporting Standard (GHG Protocol).

GHD understands that Client intends to use the GHG Inventory to supports it's Integrated Annual Report (IAR) which is published annually on Client's website for stakeholders and investors and demonstrates the evolution and growth of Client's approach to sustainability. A limited assurance statement, prepared by an accredited Verification Body, is included as part of the IAR report.

GHD has prepared this Verification Opinion in accordance with ISO Standard ISO 14064 Greenhouse gases - Part 3: Specification with guidance for the verification and validation of greenhouse gas statements (ISO 14064-3:2019).

2. Verification Objective, Standards and Criteria

The purpose of the verification was to have an independent third party assess CPC's 2025 GHG Inventory, calculations, and compliance with the requirements of ISO 14064-3:2019, the GHG Protocol, and associated guidance. The objective of the verification is to provide CPC with an opinion that the 2025 GHG Inventory did not contain any material misstatements, and that nothing could be identified in the information reported that was not accurate or consistent with the requirements of ISO 14064-3:2019 or that the 2025 GHG Inventory was not prepared in alignment with the general requirements of the GHG Protocol.

GHD applied the following verification criteria:

– ISO 14064 Greenhouse Gases - Part 1: Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals, ISO, December 2018 (ISO 14064-1)
– ISO 14064 Greenhouse Gases - Part 3: Specification with guidance for the verification and validation of greenhouse gas statements, ISO, April 2019 (ISO 14064-3)
– IAF Mandatory Document for the Use of Information and Communication Technology (ICT) for Conformity Assessment Purposes: Issue 3, International Accreditation Forum, Inc., January 2025 (IAF MD 4: 2025)
– The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (Revised Edition) (GHG Protocol)

The verification was conducted at a limited level of assurance.

The GHG Protocol states, "as a rule of thumb, an error is considered to be materially misleading if its value exceeds 5% of the total inventory for the part of the organization being verified". Consistent with this and

Independent practitioner's limited assurance report

industry practice, quantitative materiality for this verification is ±5% of the total reported GHG emissions. GHD will utilize this threshold for production quantities as well.

A series of discrete errors, omissions, or representations of individual or a series of qualitative factors, when aggregated, may be considered material.

3. GHD Accreditation

GHD is accredited by the ANSI National Accreditation Board (ANAB) under ISO 14065 as a Greenhouse Gas Validation and Verification Body. Our ANAB accreditation can be viewed at the ANAB GHG Accreditation Services website. (**https://anabpd.ansi.org/Accreditation/environmental/greenhouse-gas-validation-verification/AllDirectoryDetails?&prgID=200&OrgId=1735&statusID=4https://www.ansi.org/Accreditation/environmental/greenhouse-gas-validation-verification/AllDirectoryDetails?&prgID=200&OrgId=1735&statusID=4**)

4. Verification Scope

The GHG emission sources and specific greenhouse gases included in the GHG Inventory are from sources associated with electricity generation from natural gas fired power plants, solar facilities and wind farms. The specific GHG emissions categories included are as follows.

- Scope 1 Emissions:
  - Stationary Combustion: Carbon dioxide (CO_2), Methane (CH_4), Nitrous oxide (N_2O)
  - Industrial Product Use: Sulphur hexafluoride (SF_6)
  - On-Site Transportation: CO_2, CH_4, N_2O
  - Fugitives: CO_2, CH_4
  - Venting: CO_2, CH_4
  - Wastewater: CH_4, N_2O
- Scope 2 Emissions:
  - Imported Electricity (carbon dioxide equivalent (CO_2e))
- Production:
  - Yearly net generation (electricity a power plant supplies to the power transmission line connected to the power plant) (MWh)
- Scope 1 emissions intensity (Scope 1 emissions divided by Yearly net generation), in units of tonnes CO_2e/MWh

The Client's Corporate Operations include activities in Canada and the United States, with specific facilities and locations listed below:

Canadian Operations

- Clover Bar Energy Centre – Alberta
- Genesee Generating Station – Alberta
- Clydesdale Solar – Alberta
- Strathmore Solar – Alberta
- Halkirk Wind – Alberta
- Whitla Wind – Alberta

Independent practitioner's limited assurance report

- Island Generation Facility – British Columbia
- Quality Wind – British Columbia
- East Windsor – Ontario
- Goreway Power Station – Ontario
- York Energy Centre – Ontario
- Kingsbridge I Wind – Ontario
- Port Dover & Nanticoke Wind – Ontario

US Operations

- Decatur Energy Center – Alabama
- Arlington Valley – Arizona
- Harquahala – Arizona
- La Paloma – California
- Cardinal Point Wind – Illinois
- Bloom Wind – Kansas
- Midland Cogeneration Venture – Michigan
- Macho Springs – New Mexico
- Beaufort Solar – North Carolina
- New Frontier Wind – North Dakota
- Rolling Hills – Ohio
- Hummel Station – Pennsylvania
- Buckthorn Wind – Texas
- Frederickson 1 – Washington

The reporting period is between January 1, 2025 to December 31, 2025.

5. Verification Procedures

5.1 Conflict of Interest (COI) and Independence

GHD has undergone a thorough evaluation for conflict of interest (COI) and independence for this verification work. This included a review of other potential work conducted by GHD for CPC and the facility listed in the scope of work. We have confirmed that this verification work can be successfully completed without undue risk of impartiality and conflict of interest. We have assessed the following key aspects:

i. Verification evaluation

ii. Team evaluation

GHD has rigorous COI and verifier competency evaluation procedures that are followed for every verification project. Our documented procedures ensure that all COI and independence criteria are properly evaluated. GHD's COI program ensures that both the company and the Project Team have no potential COIs.

GHD has also evaluated and approved our Verification Team's competencies. GHD can attest that we have highly qualified staff with the appropriate technical expertise for the verification work.

Independent practitioner's limited assurance report

5.2 Methodologies Used to Assess/Verify Emissions Data

The verification procedures were used to assess the following:

1. Accuracy and completeness of the GHG Inventory
2. Uncertainty of external data sources used
3. Emission assumptions
4. Accuracy of emission calculations
5. Potential magnitude of errors and omissions

To sustain a risk-based assessment, the GHD Project Team identified and determined risks related to the GHG emissions during the document reviews, site visit and the follow-up interviews as applicable. The GHD Project Team focused on the accuracy and completeness of provided information. The components of the document review and follow-up interviews were:

– Document Review:
  - Review of data and information to confirm the correctness and completeness of presented information.
  - Confirm the GHG assertion is comprehensive and follows the structure and criteria specified in the Program and relevant guidelines.
  - Conduct crosschecks between information provided in the Emissions Report and information from independent background investigations.
  - Confirm that the quantification methodologies are accurate, transparent provide a complete overview of the Facility's GHG emissions sources and methodologies used in the GHG emission inventory, and that the methodologies used are justified and appropriate.
  - Conduct sensitivity and magnitude analyses for parameters that may be the largest sources of error
  - Compare reported emissions with the previous reporting period(s) to confirm trends.
  - Confirm that the GHG emission calculations are appropriate and use conservative assumptions for estimating GHG emissions.
  - Confirm that the GHG information system and its controls are sufficiently robust to minimize the potential for errors, omissions or misrepresentations.

Confirm that the frequency of, and responsibility and authority for, monitoring, measurement, data recordings activities and quality control/quality assurance/management control procedures is sufficient.

– Follow-up Interviews:
  - Via telephone
  - Via email
  - Via ICT

The document review established to what degree the presented GHG Inventory documentation met the verification standards and criteria.

The GHD Project Team's document review during the review process comprised of, but was not limited to, an evaluation of whether or not:

– The documentation is complete and comprehensive and follows the structure and criteria required by the Program.
– The monitoring methodologies are justified and appropriate.
– The assumptions behind the inventory are conservative and appropriate.
– The GHG emission calculations are appropriate and use conservative assumptions for estimating GHG emissions.

Independent practitioner's limited assurance report

The GHD Project Team interviewed Facility personnel to:

- Cross-check information provided
- Test the correctness of critical formulae and calculations
- Review data management and recording procedures

GHD completed checks of data from point of collection (meter, scale, etc.), through the Facility's data management systems, then it's use in the development of the Emissions Report. A sample of raw data was collected for checks and recalculations as applicable. Where errors or anomalies were identified that could lead to a material misstatement, GHD requested further raw data samples to assess the pervasiveness of the errors or anomalies, as applicable. GHD identified the source and magnitude of data or methodology errors or anomalies; however, as a verification body, GHD did not provide solutions to issues identified, where applicable.

5.3 Issues Communications

During the course of the document review and interviews, questions and clarifications were identified by the Project Team; these were communicated with Client either verbally, by email, or in an Issues Log (Excel workbook). CPC staff had the opportunity to respond to and resolve identified issues, material and/or non-material, prior to the completion of GHD's draft and final verification reports.

5.4 Independent Review

GHD conducted an independent review of the verification, which included a review of findings, emission calculations and opinion developed by the verification team.

6. Verification Opinion

CPC was responsible for the preparation and fair presentation of the GHG Inventory for the 2025 reporting year, in accordance with the criteria, and engaging with a qualified third-party verifier to verify the GHG Inventory. The Facility's GHG-related activity is detailed in Section 4.

GHD's objective and responsibility was to provide an opinion regarding whether the GHG Inventory was free of material misstatement and whether the information reported is a fair and accurate representation of the operations for the reporting period accurate and consistent.

The criteria used by GHD for the verification of the GHG Inventory is detailed in Section 2. GHD completed the verification of the GHG Inventory in accordance with ISO 14064-3:2019. GHD completed the verification to a limited level of assurance.

CPC has reported the following as their emissions and emissions intensities for the 2025 reporting period:

- Scope 1 Emissions: 20.5 million tonnes CO2e (MTCO2e)
- Net Generation: 52,655,817 MWh
- Scope 1 Emissions Intensity: 0.39 tonnes CO2e/MWh
- Scope 2 Emissions: 0.07 MT CO2e

Based on verification procedures undertaken to a limited level of assurance, it is GHD's opinion that nothing has come to GHD's attention that the GHG emissions assertion, including methodologies and proposed emissions reductions are, in all material aspects, not in accordance with the approved program verification criteria.

This opinion is effective as of 17 February 2026.

Independent practitioner's limited assurance report

7. Limitation of Liability

Because of the inherent limitations in any internal control structure, it is possible that fraud, error, or non-compliance with laws and regulations may occur and not be detected. Further, the verification was not designed to detect all weakness or errors in internal controls so far as they relate to the requirements set out above as the verification has not been performed continuously throughout the period and the procedures performed on the relevant internal controls were on a test basis. Any projection of the evaluation of control procedures to future periods is subject to the risk that the procedures may become inadequate because of changes in conditions, or that the degree of compliance with them may deteriorate.

This verification was based on a risk-based approach that follows rigorous methodology with the expectation that it will capture the majority of errors with the potential for a material misstatement. However, GHD does not warrant or guarantee that all errors or omissions, including material issues, made by Client in its Report and/or assertion were identified by GHD.

The verification opinion expressed in this report has been formed on the above basis.

GHD's review of the GHG Inventory included only the information discussed above. While the review included observation of the systems used for determination of the GHG Inventory, GHD did not conduct any direct field measurements and has relied on the primary measurement data and records provided by Client as being reliable and accurate. No other information was provided to GHD or incorporated into this review. GHD assumes no responsibility or liability for the information with which it has been provided by others.

The information and opinions rendered in this report are exclusively for use by Client. GHD will not distribute or publish this report without Client's consent except as required by law or court order. The information and opinions expressed in this report are given in response to a limited assignment and should only be evaluated and implemented in connection with that assignment. GHD accepts responsibility for the competent performance of its duties in executing the assignment and preparing this report in accordance with the normal standards of the profession but disclaims any responsibility for consequential damages.

Regards

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Consolidated financial statements

(in millions of Canadian dollars)
Years ended December 31, 2025 and 2024

Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of Capital Power Corporation (the Company) are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with International Financial Reporting Standards (IFRS) Accounting Standards as issued by the International Accounting Standards Board (IASB). The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 3, 2026. Financial information presented elsewhere in the Company's Integrated Annual Report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with IFRS Accounting Standards. The independent auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and Integrated Annual Report and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Avik Dey
President and Chief Executive Officer

Scott Manson
Interim Senior Vice President,
Finance and Chief Financial Officer

March 3, 2026

Independent auditor's report

KPMG LLP
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Canada
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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Capital Power Corporation

Opinion

We have audited the consolidated financial statements of Capital Power Corporation (the Entity), which comprise:

- the consolidated statements of financial position as at December 31, 2025 and December 31, 2024
- the consolidated statements of income for the years then ended
- the consolidated statements of comprehensive (loss) income for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at December 31, 2025 and December 31, 2024, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS) Accounting Standards as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independent auditor's report

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2025. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditor's report.

Evaluation of the fair value of level 3 derivative financial instruments

Description of the matter

We draw your attention to Note 2(k), Note 13, and Note 27 to the financial statements. The Entity has recorded derivative financial instruments assets of $70 million and liabilities of $338 million within level 3 of the fair value hierarchy at December 31, 2025. The estimate of fair value for level 3 derivative financial instruments contains significant unobservable inputs, including forward pricing and anticipated generation based on the Entity's internally developed models.

Why the matter is a key audit matter

We identified the evaluation of the fair value of level 3 derivative financial instruments as a key audit matter. This matter represented an area of significant risk of material misstatement requiring significant auditor effort and specialized skills and knowledge to evaluate the Entity's internally developed fair value models.

How the matter was addressed in the audit

The primary procedures we performed to address this key audit matter included the following:

We inspected the terms of relevant underlying contracts and compared these to the Entity's internally developed models of fair value for the level 3 derivative financial instruments.

For level 3 derivative financial instruments where anticipated generation was an unobservable input:

- We involved valuation professionals with specialized skills and knowledge to assess the appropriateness of the Entity's internally developed model for a selection of the contracts.
- To assess the appropriateness of the Entity's internally developed models we compared them to the models used in the prior year.
- To assess the appropriateness of anticipated generation used in the models for operating assets, we compared the anticipated generation predicted by the models in the prior year to the actual generation.

For level 3 derivative financial instruments where forward pricing was an unobservable input:

- We involved valuation professionals with specialized skills and knowledge to assess the appropriateness of the forward pricing in the Entity's internally developed model for a selection of contracts by comparing to independently derived forward pricing.
- To assess the appropriateness of the Entity's internally developed models we compared them to the models used in the prior year.

Independent auditor's report

KPMG

Evaluation of the acquisition-date fair value of PP&E of Hummel Station, LLC and Rolling Hills Generating, LLC

Description of the matter

We draw attention to Note 2(d), Note 3 and Note 4 to the financial statements. The Entity acquired 100% of the equity interests in Hummel Station, LLC ("Hummel") and Rolling Hills Generating, LLC ("Rolling Hills"). The acquisition-date fair value of Hummel and Rolling Hills property, plant and equipment ("PP&E") was $3,010 million. The determination of the acquisition-date fair value of this PP&E involves significant estimates, which includes estimates of replacement cost and reflects adjustments for physical deterioration as well as functional and economic obsolescence.

Why the matter is a key audit matter

We identified the evaluation of the acquisition-date fair value of PP&E of Hummel and Rolling Hills as a key audit matter. Significant auditor judgment was required in evaluating the results of our audit procedures regarding the estimates of the replacement cost and adjustments for physical deterioration of the acquired PP&E. Further, specialized skills and knowledge were needed to evaluate this estimate.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

We involved valuation professionals with specialized skills and knowledge who assisted in:

- Assessing the appropriateness of the Entity's estimate of replacement cost of a selection of the Hummel and Rolling Hills PP&E by comparing the Entity's estimate to market data for comparable assets
- Assessing the appropriateness of adjustments for physical deterioration by comparing a selection of the Entity's estimated depreciated costs to a depreciation cost range that was independently developed using market data for comparable assets
- Performing a physical site inspection to examine the physical deterioration of a selection of the Hummel and Rolling Hills PP&E.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis
- the information, other than the financial statements and the auditor's report thereon, included in a document likely to be entitled "2025 Integrated Annual Report".

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

Independent auditor's report

We obtained the information included in Management's Discussion and Analysis and the "2025 Integrated Annual Report" as at the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

Independent auditor's report

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the group as a basis for forming an opinion on the group financial statements. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.
- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditor's report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

KPMG LLP

Chartered Professional Accountants

The engagement partner on the audit resulting in this auditor's report is Robert Borrelli.

Edmonton, Canada

March 3, 2026

Consolidated statements of income

(In millions of Canadian dollars, except per share amounts)

Year ended December 31,		2025		2024
Revenues	**$**	**3,615**	$	3,677
Other income (note 5)		**105**		99
Energy purchases and fuel		**(2,101)**		(1,787)
Gross margin		**1,619**		1,989
Other raw materials and operating charges		**(224)**		(209)
Staff costs and employee benefits expense (note 6)		**(183)**		(254)
Depreciation and amortization		**(580)**		(503)
Other administrative expense		**(246)**		(201)
Foreign exchange gain (loss)		**21**		(29)
Impairment (note 30)		**–**		(27)
Operating income		**407**		766
Net finance expense (note 7)		**(307)**		(221)
Income from equity-accounted investments (note 30)		**77**		76
Loss on disposals and other transactions (note 14)		**(10)**		(31)
Gain on divestiture (note 30)		**–**		309
Income before tax		**167**		899
Income tax expense (note 8)		**(8)**		(198)
Net income	**$**	**159**	$	701
Attributable to:				
Non-controlling interests	**$**	**(1)**	$	2
Shareholders of the Company	**$**	**160**	$	699
Earnings per share attributable to shareholders of the Company:				
Basic (note 9)	**$**	**0.88**	$	5.16
Diluted (note 9)	**$**	**0.88**	$	5.15

See accompanying notes to the consolidated financial statements

Consolidated statements of comprehensive (loss) income

(in millions of Canadian dollars)

Year ended December 31,		2025		2024
Net income	**$**	**159**	$	701
Other comprehensive (loss) income:				
Items that will not be reclassified subsequently to net income:				
Actuarial gains on defined benefit plans[1]		**–**		1
Items that may be reclassified subsequently to net income:				
Unrealized gains on derivative instruments[2] (note 13)		**12**		81
Reclassification of gains on derivative instruments to net income[3] (note 13)		**(34)**		(25)
Equity-accounted investments[4]		**(8)**		4
Net investment in foreign operations:				
Unrealized (losses) gains[5]		**(149)**		218
Other comprehensive (loss) income, net of tax		**(179)**		279
Total comprehensive (loss) income	**$**	**(20)**	$	980
Attributable to:				
Non-controlling interests	**$**	**(1)**	$	2
Shareholders of the Company	**$**	**(19)**	$	978

1 For the year ended December 31, 2025 and December 31, 2024, net of income tax of nil, respectively.
2 For the year ended December 31, 2025 and December 31, 2024 net of income tax expense of $5 and $15, respectively.
3 For the year ended December 31, 2025 and December 31, 2024 net of reclassification of income tax expense of $10 and $8, respectively.
4 For the year ended December 31, 2025 and December 31, 2024 net of income tax recovery of $3 and income tax expense $2, respectively.
5 For the year ended December 31, 2025 and December 31, 2024, net of income tax of nil and nil, respectively.

See accompanying notes to the consolidated financial statements

Consolidated statements of financial position

(In millions of Canadian dollars)

At December 31,		**2025**		2024
Assets				
Current assets:				
Cash and cash equivalents (note 10)	**$**	**119**	$	865
Trade and other receivables (note 11)		**569**		507
Income taxes recoverable (note 8)		**216**		97
Inventories (note 12)		**323**		235
Derivative financial instruments (note 13)		**315**		244
		1,542		1,948
Non-current assets:				
Property, plant and equipment (note 4 and 17)		**11,253**		8,061
Equity-accounted investments (note 30)		**1,064**		1,096
Intangible assets and goodwill (note 16)		**620**		744
Right-of-use assets (note 15)		**136**		118
Derivative financial instruments (note 13)		**373**		412
Government grants receivable (note 14)		**320**		380
Deferred tax assets (note 8)		**26**		26
Other assets		**107**		145
Total assets	**$**	**15,441**	$	12,930
Liabilities and equity				
Current liabilities:				
Trade and other payables (note 18)	**$**	**789**	$	751
Derivative financial instruments (note 13)		**274**		147
Loans and borrowings (note 19)		**347**		157
Provisions (note 22)		**112**		85
Deferred revenue and other liabilities (note 21)		**113**		213
		1,635		1,353
Non-current liabilities:				
Derivative financial instruments (note 13)		**719**		494
Loans and borrowings (note 19)		**6,383**		4,819
Lease liabilities (note 20)		**154**		134
Deferred tax liabilities (note 8)		**904**		863
Provisions (note 22)		**504**		373
Deferred revenue and other liabilities (note 21)		**293**		323
Total liabilities	**$**	**10,592**	$	8,359
Share capital (note 23)		**5,036**		4,301
Deficit		**(349)**		(74)
Other reserves		**170**		349
Equity attributable to shareholders of the Company	**$**	**4,857**	$	4,576
Non-controlling interests		**(8)**		(5)
Total equity		**4,849**		4,571
Total liabilities and equity	**$**	**15,441**	$	12,930

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board:

Jill Gardiner
Director and Chair of the Board

Barry Perry
Director and Chair of the Audit Committee

Consolidated statements of changes in equity

(In millions of Canadian dollars)

	Share capital (note 23)	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	–	–	–	–	–	160	160	(1)	159
Other comprehensive loss	–	(30)	(149)	–	–	–	(179)	–	(179)
Total comprehensive (loss) income	–	(30)	(149)	–	–	160	(19)	(1)	(20)
Issue of share capital, net[2] (note 23)	656	–	–	–	–	–	656	–	656
Common share dividends (note 23)	–	–	–	–	–	(407)	(407)	–	(407)
Preferred share dividends, net of tax[3] (note 23)	–	–	–	–	–	(28)	(28)	–	(28)
Dividends reinvested	79	–	–	–	–	–	79	–	79
Distributions to non-controlling interests	–	–	–	–	–	–	–	(2)	(2)
Balance, December 31, 2025	$ 5,036	$ 78	$ 91	$ (9)	$ 10	$ (349)	$ 4,857	$ (8)	$ 4,849

1 Accumulated other comprehensive income. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income and the employee benefits reserve.
2 Net of share issue costs of $28, income tax recovery of $7, and share options exercised of $10.
3 Including income tax expense of $1.

See accompanying notes to the consolidated financial statements

Consolidated statements of changes in equity

(In millions of Canadian dollars)

	Share capital (note 23)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Balance, January 1, 2024	$ 3,524	$ 48	$ 22	$ (10)	$ 10	$ (404)	$ 3,190	$ (4)	$ 3,186
Net income	–	–	–	–	–	699	699	2	701
Other comprehensive income	–	60	218	1	–	–	279	–	279
Total comprehensive income	–	60	218	1	–	699	978	2	980
Issue of share capital, net (note 23)[2]	833	–	–	–	–	–	833	–	833
Common share dividends (note 23)	–	–	–	–	–	(335)	(335)	–	(335)
Preferred share dividends, net of tax[3] (note 23)	–	–	–	–	–	(34)	(34)	–	(34)
Preferred share redemption	(150)	–	–	–	–	–	(150)	–	(150)
Dividends reinvested	67	–	–	–	–	–	67	–	67
Share options exercised	27	–	–	–	–	–	27	–	27
Distributions to non-controlling interests	–	–	–	–	–	–	–	(3)	(3)
Balance, December 31, 2024	$ 4,301	$ 108	$ 240	$ (9)	$ 10	$ (74)	$ 4,576	$ (5)	$ 4,571

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 $35 and income tax recovery of $8.
3 Including income tax expense of $3.

See accompanying notes to the consolidated financial statements

Consolidated statements of cash flows

(In millions of Canadian dollars)

Year ended December 31,	2025	2024
Cash flows from operating activities:		
Net income	$ 159	$ 701
Non-cash adjustments:		
Depreciation and amortization	580	503
Net finance expense (note 7)	307	221
Impairment	–	27
Fair value changes on commodity derivative instruments and emission credits held for trading	342	(238)
Foreign exchange (gains) losses	(21)	29
Income tax expense (note 8)	8	198
Income from equity-accounted investments (note 30)	(77)	(76)
Tax-equity attributes (note 5)	(76)	(76)
Gain on divestiture (note 30)	–	(309)
Other	34	44
Change in fair value of derivative instruments, cash settlement	(8)	13
Distributions received from equity-accounted investments (note 30)	66	120
Interest paid	(304)	(163)
Income taxes paid	(20)	(38)
Other	(21)	15
Change in non-cash operating working capital (note 24)	(7)	173
Net cash flows from operating activities	962	1,144
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets, net[1]	(864)	(1,070)
Business acquisition, net of acquired cash (note 4)	(2,971)	(908)
Acquisition of equity-accounted investment	–	(316)
Government grants received (note 14)	60	50
Divestiture (note 30)	–	333
Other	14	(5)
Net cash flows used in investing activities	(3,761)	(1,916)
Cash flows from (used in) financing activities:		
Net proceeds from issue of loans and borrowings[2] (note 19)	2,488	1,041
Repayment of loans and borrowings	(650)	(781)
Capitalized interest paid (note 7)	(40)	(56)
Issue of share capital[3] (note 23)	649	459
Dividends paid (note 23)	(338)	(280)
Redemption of preferred shares (note 23)	–	(150)
Income taxes paid on preferred share dividends	(11)	(13)
Distributions to non-controlling interests	(2)	(3)
Other	(19)	(15)
Net cash flows from financing activities	2,077	202
Foreign exchange (loss) gain on cash held in foreign currency	(24)	17
Cash derecognized on loss of control of subsidiaries (note 30)	–	(5)
Net decrease in cash and cash equivalents	(746)	(558)
Cash and cash equivalents, beginning of year	865	1,423
Cash and cash equivalents, end of year	$ 119	$ 865

1 Reflects total additions increased by $168 for changes in non-cash investing working capital and other non-current assets and liabilities (2024 – reduced by $124).
2 Net of deferred debt issue costs of $19 (2024 – $9).
3 Net of share issue costs of $28 and share purchase options exercised of $10 (2024 - $27 and $26, respectively).

See accompanying notes to the consolidated financial statements

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns, and operates utility-scale renewable and 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”.

2. Material accounting policies:

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) Accounting Standards as issued by the International Accounting Standards Board (IASB).

These consolidated financial statements have been prepared under the historical cost basis, except for the Company’s derivative instruments, emission credits held for trading, defined benefit pension plan assets and cash-settled share-based payments, which are stated at fair value.

These consolidated financial statements were approved and authorized for issue by the Board of Directors on March 3, 2026.

(b) Basis of consolidation:

These consolidated financial statements include the accounts of Capital Power and its subsidiaries. Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Company obtains control, and continue to be consolidated until the date that such control ceases to exist.

The Company has a 100% interest in each of Capital Power L.P. (CPLP), Capital Power L.P. Holdings Inc., and Capital Power (US Holdings) Inc., which are all controlled by Capital Power and are therefore treated as subsidiaries of the Company.

Non-controlling interests in subsidiaries are identified separately from equity attributable to shareholders of the Company. Subsequent to acquisition, the carrying amount of non-controlling interests is the amount of those interests at initial recognition plus the non-controlling interest’s share of subsequent changes in equity.

When the Company loses control over a subsidiary, it derecognizes the assets and liabilities of the subsidiary, and any related non-controlling interests and other components of equity. Any resulting gain or loss is recognized in profit or loss. Any interest retained in the former subsidiary is measured at fair value when control is lost.

All significant intercompany balances and transactions have been eliminated on consolidation.

(c) Accounting changes:

Future accounting changes:

- 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 aim 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 include 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 are effective for annual reporting periods beginning on or after January 1, 2026, with early application permitted.

- 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 clarify the date of recognition and derecognition of financial assets and liabilities, and introduce an exception for the derecognition of financial liabilities settled through electronic payment systems, when certain criteria are met. The amendments also clarify the application of the solely payments of principal and interest (SPPI) criterion and add new disclosures for financial instruments with contractual terms that can change the cash flows. The amendments are effective for annual periods beginning on or after January 1, 2026.

- 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 introduces key new requirements on presentation and disclosures in the financial statements, with a focus on the statement of profit or loss and reporting of financial performance. IFRS 18 will replace IAS 1 Presentation of Financial Statements and will be effective for annual reporting periods beginning on or after date January 1, 2027, with early application permitted.

Management is currently assessing the impact of the amendments and IFRS 18 on the Company’s consolidated financial statements.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(d) Business combinations and goodwill:

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration of an acquisition is measured as the fair value of the assets given, equity instruments issued, and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed.

Identifiable assets acquired, and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition.

Transaction costs and other acquisition costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

The Company elects on a transaction-by-transaction basis whether to measure a non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date.

(e) Investments in joint arrangements:

Investments in joint operations

Capital Power has interests with other parties (the Joint Operators), whereby in each case the Joint Operators have a contractual arrangement that establishes the Joint Operators' rights to the assets and obligations for the liabilities of the arrangement. These arrangements are considered to be joint operations.

In these situations, Capital Power recognizes its share of the joint operations' assets and liabilities in accordance with those associated rights and obligations, along with its share of the revenues from the output of the joint operation and its share of any expenses incurred. The accounting policies of these joint operations are aligned with the accounting policies of the Company.

Investment in joint ventures

When the Company has joint control in a partnership with an external party where, by contractual agreement, each of the Partners effectively has rights to the net assets of the arrangement, the arrangement is considered to be a joint venture.

The Company's investments in joint ventures are accounted for under the equity method and recognized initially at cost. The carrying amount of each investment is increased or decreased to recognize the Company's share of the joint venture's total comprehensive income or loss after the date of acquisition. Distributions received from joint ventures reduce the carrying amounts of the investments. The accounting policies of joint ventures are aligned with the accounting policies of the Company.

(f) Foreign currency translation:

Transactions in foreign currencies are recorded in the respective functional currencies of the Company, or the subsidiary concerned, at exchange rates in effect at the transaction date. At each reporting date, monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the date of the statement of financial position. Revenues, other income and expenses are translated using monthly average exchange rates. The resulting foreign exchange gains and losses are included in net income.

On consolidation, the assets and liabilities of U.S. operations that have a functional currency that is different from the Company's functional currency of Canadian dollars are translated into Canadian dollars at the exchange rates in effect at the date of the statement of financial position. Revenues, other income and expenses are translated at monthly average exchange rates. The resulting translation gains and losses are deferred and included in accumulated other comprehensive income (loss) as unrealized gains and losses on net investment in foreign operations.

(g) Government grants:

The Company's government grants include:

- compensation to be received from the Province of Alberta (the Province) through 2030 related to the phase-out of coal-fired generation (see note 14),
- government assistance for certain U.S. income tax benefits received under tax-equity structures with participating investors, and
- government contribution and credits for eligible projects (including Clean Technology Investment Tax Credits (ITC) for Halkirk 2 Wind, and Battery Energy Storage Systems (BESS) projects in Ontario (see note 14).

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(g) Government grants, continued:

The Company accounts for government grants using the income approach and recognizes them initially at fair value, and subsequently at amortized cost using the effective interest method. Such grants are recorded as a receivable (except as noted below) and deferred revenue when there is reasonable assurance that they will be received and that the Company will comply with the conditions associated with the respective grant. Interest income is accrued on the government grants receivable, within net finance expense, until the final payments are received. The associated deferred revenue is recognized as other income on a straight-line basis over the depreciable life of the respective assets or over the period which the related expenses are incurred, as applicable on a grant-by-grant basis.

For government assistance related to U.S. income tax benefits received under tax-equity structures, tax benefits received are recorded within loans and borrowings.

(h) Revenue recognition:

Major types of revenues include energy revenues and emission credit revenues. When multiple promises exist in a single customer contract, management assesses whether these promises are distinct performance obligations or a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. This determination of performance obligations affects whether the transaction price is recognized over time or at a point in time. Revenues excluded from the scope of IFRS 15 - Revenue from Contracts with Customers are disclosed as revenues from other sources and consist of contracts accounted for under IFRS 16 – Leases (note 2(i)) and IFRS 9 – Financial Instruments.

Contracts with customers

Revenue type	Description
Energy revenues	Electricity supply contracts generally include a single performance obligation that is satisfied over time. Revenues from the sale of electricity are recognized under the right to invoice practical expedient, which is generally upon delivery or availability for delivery under the respective contracts. In instances where the right to invoice practical expedient cannot be applied, energy revenues are recognized as the performance obligation is satisfied and measured under the output method which is based on energy generated, or availability, depending on the nature of the contracts with customers.
Emission credit revenues	Renewable energy certificates (RECs) generated by certain of the Company's facilities are sold to the respective customers under the terms of fixed price agreements. Revenues from RECs are recognized when the performance obligations are satisfied at the specified transaction price. This can occur when physical control of RECs is transferred to the customer or recognized upon production and delivery of the electricity pursuant to an agreement for the bundled sale of electricity and RECs.

Derivative instruments

Revenues also include realized and unrealized gains and losses from derivatives used in the risk management of the Company's generation activities related to commodity prices, and from the Company's proprietary trading activities. Realized gains and losses are recognized when the settlement of trading positions occurs and unrealized gains and losses are recognized as revenues based on the related changes in the fair value of the financial instrument at the end of each reporting period (note 2(k)).

Deferred revenue

The government grants described in note 2(g) are recorded as deferred revenue. Accretion of the deferred revenue is recognized in net finance expense on the consolidated statements of income.

Monetary contributions received from external parties used to provide the Company with ongoing access to a supply of goods or services are measured at fair value of the cash received and are initially recorded as deferred revenue. Revenue is recognized straight-line over the life of the associated depreciable asset or as the service is performed, or if an ongoing service is performed as part of an agreement, over the lesser of the life of the agreement and the life of the asset.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(i) Leases or arrangements containing a lease:

At inception of a contract, the Company assesses whether a contract is, or contains a lease. This assessment involves determining whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Lessor

At lease inception, the Company determines whether the lease transfers substantially all risks and rewards incidental to ownership of the underlying asset. If this is the case, then the lease is classified as a finance lease; otherwise, it is classified as an operating lease and revenues are recognized on a straight-line basis as part of energy revenues.

Lessee

The Company recognizes a right-of-use asset and lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred, less any lease incentives received. The right-of-use asset is depreciated using the straight-line method from the commencement date to the end of the lease term, unless the lease transfers ownership of the underlying asset to the Company by the end of the lease term or the cost of the right-of-use asset reflects that the Company will exercise a purchase option. In that case, the right-of-use asset would be depreciated over the useful life of the underlying asset. Lease payments are recorded as a reduction of the lease liability and interest expense. Interest expense is recognized using the effective interest method. The Company is the lessee in contracts for various office, equipment, and land leases.

(j) Non-derivative financial instruments:

Classification

The Company classifies its non-derivative financial instruments in the following categories: fair value through profit or loss (FVTPL) or amortized cost.

The Company determines the classification of financial assets and liabilities at initial recognition. Classification of financial assets and liabilities is determined based on the business model by which assets and liabilities are managed and their cash flow characteristics.

Financial assets and liabilities are measured at FVTPL if they are classified as held for trading or are designated as such upon initial recognition.

Measurement

Financial assets and liabilities at fair value through profit or loss

Upon initial recognition, transaction costs are recognized into net income as incurred. Financial assets and liabilities classified as held at FVTPL are measured at fair value with the changes in fair value reported in net income. Fair values are determined in the manner described in note 3. Gains or losses realized on derecognition of investments held at FVTPL are recognized into net income.

Financial assets and liabilities at amortized cost

The Company's financial assets measured at amortized cost are comprised of cash and cash equivalents, trade and other receivables, and government grants receivable.

Financial assets are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses as described in note 2(n). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

The Company's financial liabilities measured at amortized cost are comprised of loans and borrowings and trade and other payables and are recognized on the date at which the Company becomes a party to the contractual arrangement.

Financial liabilities are recognized initially at fair value plus any directly attributable transaction costs, such as debenture discounts, premiums and issue expenses. Subsequently these liabilities are measured at amortized cost using the effective interest method. Liabilities are derecognized when the contractual obligations are discharged, cancelled or expired.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set-off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(j) Non-derivative financial instruments, continued:

Measurement, continued

Financial assets and liabilities at fair value through profit or loss, continued

The Company participates in tax-equity structures with project investors which have financed the construction of certain renewables projects. Such tax-equity structures are used in the U.S. to provide investors with access to U.S. income tax benefits such as investment tax credits, cash grants, production tax credits, and accelerated tax depreciation. In return for purchasing equity stakes in these projects, the project investors receive a substantial portion of earnings, tax benefits and cash flows from the projects financed with a tax-equity structure until the projects have yielded an agreed-upon target rate of return to the project investors. Immediately thereafter, the structures “flip” such that the Company receives the majority of earnings, tax benefits and cash flows from the projects financed with tax-equity structures. The dates of the “flips” are dependent on the performance of the respective projects. In accordance with the substance of the contractual agreements, 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 respective “flip” dates of the projects. Subsequent to the “flip” dates, the project investor’s equity investments will be accounted for as non-controlling interests. At all times, both before and after the projects “flip”, the Company retains control over the projects financed with a tax-equity structure.

The loans and borrowings associated with the tax-equity structures are measured at amortized cost using the effective interest method and are settled over time through the following components:

Components	Description
Production tax credits (PTCs)	Allocation of PTCs to the tax-equity investor derived from the power generated by the respective renewables facility during the period and recognized in other income as earned.
Taxable income (loss), including tax attributes such as accelerated tax depreciation	Allocation of taxable income (loss) and other tax attributes to the tax-equity investor recognized in other income as earned.
Cash distributions	Cash allocation to the tax-equity investor.

(k) Derivative instruments and hedging activities:

Classification and measurement

All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting requirements are met and the derivative is designated as a hedge, in which case such derivatives are classified as fair value through other comprehensive income (FVTOCI). Realized gains and losses on financial energy derivatives classified as FVTOCI are recorded in revenues or energy purchases and fuel. Realized gains and losses on interest rate derivatives classified as FVTOCI are recorded in net finance expense during the periods when the variability in cash flows of the hedged items affect net income. Realized gains and losses on foreign exchange derivatives classified as FVTOCI are recorded in foreign exchange gains or losses, or where the hedged transaction results in the recognition of net assets, those realized gains or losses will be included in the initial carrying amount of those net assets. Fair values are determined in the manner described in note 3.

If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel as appropriate, unrealized and realized gains and losses on financial interest rate derivatives are recorded in net finance expense and such gains and losses on financial foreign exchange derivatives are recorded in foreign exchange gains and losses.

All derivative instruments, including embedded derivatives, are recorded at fair value on the statement of financial position as derivative financial instruments assets or derivative financial instruments liabilities except for embedded derivative instruments that are clearly and closely related to their host contract and the combined instrument is not measured at fair value.

Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company’s expected purchase, sale or usage requirements. The Company accounts separately for any embedded derivatives in any hybrid instruments issued or acquired.

The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter quotations by reference to bid or asking price, as appropriate, in active markets if available. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management’s best estimates using external readily observable market data such as broker quotes, future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. 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.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Hedge accounting

The Company may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income (loss), while the ineffective portion is recognized in revenues, energy purchases and fuel, net finance expense or foreign exchange gains or losses as appropriate. The amounts recognized in other comprehensive income (loss) as cash flow hedging gains or losses are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income when it becomes probable that the hedged items will not occur.

A hedging relationship is discontinued when it no longer meets the risk management objective and qualifying criteria for hedge accounting. If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive loss as part of cash flow hedging gains or losses and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income (loss) are recognized in net income in the same period as the corresponding gains or losses on the hedged item.

When it is no longer probable that an anticipated transaction will occur near the originally determined period and the associated cash flow hedge has been discontinued, any remaining gains or losses associated with the hedging item that were previously recognized in other comprehensive income (loss) are recognized in net income in the period.

(l) Property, plant and equipment:

Property, plant and equipment is recorded at cost, net of accumulated depreciation and accumulated impairment losses, if any.

Capitalization

Cost includes contracted services, materials, borrowing costs on qualifying assets, direct labour, directly attributable overhead costs, development costs associated with specific property, plant and equipment and asset retirement costs. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing a part of property, plant and equipment is capitalized if it is probable that the future economic benefits of the part will flow to the Company and that its cost can be measured reliably. The carrying amount of the replaced part is derecognized. Costs of day-to-day repairs and maintenance costs are expensed as incurred.

Depreciation

Depreciation is charged to net income on a straight-line basis over the estimated useful lives of each major component of property, plant and equipment, since this most closely reflects the expected pattern of consumption of the asset. Major components of property, plant and equipment are depreciated separately over their respective useful lives which, for our generation facilities and equipment, range from 1 to 50 years. Land and construction work in progress are not depreciated. The estimated useful lives, residual values and methods of depreciation are reviewed annually, and adjusted prospectively if appropriate.

Gains and losses on the disposal or retirement of an item of property, plant and equipment are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. Gains or losses on disposals are recognized on their own line within the consolidated statements of income while losses on retirements are recognized within depreciation and amortization.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(m) Intangible assets:

Capitalization

Intangible assets with definite lives are recorded at cost, net of accumulated amortization and accumulated impairment losses, if any. Intangible assets with definite lives are generally amortized over the related assets useful lives, as described below. Costs for third-party cloud software are expensed over the period of the agreement when the Company determines that it has not obtained control of the cloud software. Refer to note 16 for additional discussion on intangible assets.

Amortization

Amortization is charged to net income on a straight-line basis to write-off the cost less the estimated residual value over the estimated remaining term of the agreement or in line with the life of the related generating facility to which it relates. Software work in progress is not amortized as the software is not available for use. Land lease rights are amortized when the related wind power assets are constructed and commissioned for service over the lives of the related wind power assets or the term of the lease, whichever is shorter. The Company's purchased emission credits held for compliance purposes are not amortized, but are expensed as the associated benefits are realized. Such emission credits have definite lives as prescribed by their respective vintage years and any emission credits not used by the end of their lives are expensed at that time.

The periods over which intangible assets are amortized are as follows:

Contract rights	16 to 30 years
Software	5 to 35 years

Estimated useful lives, methods of amortization and residual values are reviewed annually and adjusted prospectively if required.

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount of the asset and are recognized into net income as gains or losses on disposals.

(n) Impairment of assets:

Non-financial assets

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into a cash-generating unit (CGU), which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

The Company reviews the recoverability of non-financial assets subject to depreciation or amortization (right-of-use assets, property, plant and equipment and definite life intangible assets) when events or changes in circumstances may indicate or cause the asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired.

The asset's recoverable amount is the higher of its fair value less costs to sell and its value in use. The value in use is the present value of expected future cash flows discounted using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. Fair value less costs to sell is determined using estimated market values utilizing actual market transactions, if available. When actual market transactions are not available, a valuation model is used.

Any impairment loss is recorded in net income in the period when it is determined that the carrying amount of the asset may not be recoverable. The impairment loss is recorded as the excess of the carrying amount of the asset over its recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs, and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis. An impairment loss in respect of goodwill is not reversed.

Financial assets

The Company applies the expected credit loss (ECL) impairment model to all financial assets.

The Company has applied the simplified approach to providing for ECLs prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade and other receivables.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(n) Impairment of assets, continued:

Financial assets, continued

For all other financial assets, expected allowances are recognized as 12-month ECLs unless the credit risk of a financial asset has increased significantly, in which case lifetime ECL measurement applies. The Company has identified no financial instruments for which credit risk has increased significantly since initial recognition nor financial assets that are impaired at December 31, 2025. Credit risk management procedures, including risk mitigation practices, are as described in note 28.

(o) Income taxes:

Income tax expense is comprised of current and deferred tax. Current and deferred tax is recognized in net income or loss, except to the extent that it relates to a business combination, or items recognized directly in equity, other comprehensive income (loss).

Current income taxes

Current income taxes comprise the expected tax payable or receivable on the taxable income or loss for the year and any adjustment to the tax payable or receivable in respect of previous years. The amount of current income tax payable or receivable is the best estimate of the tax amount expected to be paid or received that reflects any uncertain tax provisions, if any. It is measured using tax rates enacted or substantively enacted at the reporting date. The Company recognizes the income tax benefit of an uncertain tax position only when it is more likely than not that the ultimate determination of the tax treatment of the position will result in that benefit being realized; however, this does not mean that tax authorities cannot challenge these positions. Current income taxes also include any tax arising from dividends.

Deferred income taxes

Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the respective amounts used for taxation purposes. Deferred income taxes are not recognized for:

- temporary differences from the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither the taxable nor the accounting income and does not give rise to equal taxable and deductible temporary differences;
- temporary differences related to investments in subsidiaries, associates and joint arrangements to the extent that the Company is able to control the timing of the reversal of the temporary differences and it is probable that they will not reverse in the foreseeable future; and
- taxable temporary differences arising on the initial recognition of goodwill.

Deferred income tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable income will be available against which they can be used. Future taxable income is determined based on the Company's cash flow projections, which include estimates described in note 3 and on the reversal of relevant temporary differences. Deferred income tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable the related tax benefit will be realized; such reductions are reversed when the probability of future taxable income improves. Unrecognized deferred income tax assets are reassessed at each reporting date and recognized to the extent that it has become probable that future taxable income will be available against which they can be used.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date. The measurement of deferred income taxes reflects the tax consequences that would follow from the manner in which the Company expects, at the reporting date, to recover or settle the carrying amount of its assets and liabilities.

Current and deferred income tax assets and liabilities are only offset if certain criteria are met.

(p) Inventories:

Parts and other consumables and fuel, principally all of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of any assembled inventory includes direct labour, materials and directly attributable overhead. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs.

Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date.
Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstance.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Material accounting policies, continued:

(q) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid investment-grade short-term investments with original terms to maturity of three months or less, and are measured at amortized cost using the effective interest method.

(r) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic resources will be required to settle the obligation. The obligation is discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation for which the estimates of future cash flows have not been adjusted. The change in discount rate due to the passage of time is recognized in net finance expense and is recorded over the estimated period until settlement of the obligation. Provisions are reviewed and adjusted, when required, to reflect the current best estimate at the end of each reporting period.

The Company recognizes decommissioning provisions in the period in which a legal or constructive obligation is incurred. A corresponding decommissioning cost is added to the carrying amount of the associated property, plant and equipment, and it is depreciated over the estimated useful life of the asset. Unwinding of the discount rate on the decommissioning provisions is recorded in net finance expense over the estimated useful lives of the assets.

(s) Share-based payments:

The Company determines the fair value of stock options, classified as equity-settled awards, using a binomial option pricing model at the date of grant. Measurement inputs include the share price on the measurement date, the exercise price of the instrument, expected volatility, expected term of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

The Company has incorporated an estimated forfeiture rate for stock options that will not vest into its determination of share-based compensation for each period.

The Company also operates share-based compensation plans for certain senior employees under a Performance Share Unit (PSU) Plan and a Restricted Share Unit (RSU) Plan. Share-based compensation for directors operates under a directors' Deferred Share Unit (DSU) Plan. The fair values of the amounts payable to employees/directors in respect of the PSU, RSU, and DSU Plans, which are settled in cash, are recognized as expenses with corresponding increases in liabilities, over the period that the employees/directors unconditionally become entitled to payments. The PSU Plan and RSU Plan grant date fair values are determined using a binomial lattice valuation based on a five-day weighted average price of the Company's shares immediately prior to the grant, adjusted for estimated forfeitures and discounted using the risk-free interest rate. The DSU Plan grant date fair values are determined using the five-day weighted average price of the Company's shares immediately prior to the grant. The liability is re-measured to fair value at each reporting date and at the settlement date. Any changes in the fair value of the liability are recognized in income or loss.

(t) Earnings per share:

Basic earnings per share is calculated by dividing income available to common shareholders, less preferred share dividends declared net of tax, by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated on the treasury stock method, by dividing income available to common shareholders, less preferred share dividends declared net of tax, adjusted for the effects of dilutive securities, by the weighted average number of common shares outstanding during the period and all additional common shares that would have been outstanding had all potential dilutive common shares been issued.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

3. Use of judgments and estimates:

The preparation of the Company's consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses in the consolidated financial statements and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. The Company reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's consolidated financial statements relate to:

Non-financial assets

The determination of CGUs was based on management's judgment and considers geographic proximity and shared risk exposure and risk management. Identifying events or changes in circumstances that may indicate or cause an asset's carrying amount to exceed its recoverable amount requires judgment in assessing what events or circumstances would have such an impact.

Determining whether an arrangement contains a lease

The Company has exercised judgment in determining whether certain arrangements contains a lease. This includes assessing whether a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration for each agreement that was evaluated.

As noted in note 2(i), the Company has exercised judgment in determining whether the control of its generation assets which are subject to a PPA are transferred to the contracted purchaser under the PPA, in determining whether a lease exists. Details of those PPAs are provided in note 15.

Classification of joint arrangements structured through a separate vehicle

The Company has exercised judgment in determining the classification of joint arrangements structured through separate vehicles as described in note 30.

Assessment of Control

The assessment of control over the Company's interests in partially owned subsidiaries is based on a review of the facts and circumstances, including key terms of the relevant agreements, and requires significant management judgment.

Key sources of estimation uncertainty

The main sources of estimation uncertainty in preparing the Company's consolidated financial statements relate to:

Measurement of fair values

Several of the Company's accounting policies and disclosures require the measurement of fair values, for both financial and non-financial assets and liabilities. Fair value represents the Company's estimate of the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements recognized in the consolidated statements of financial position, as well as those included within note disclosures, are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs. Precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

Measurement of fair values, continued

The determination of fair value requires judgment and is based on market information where available and appropriate. The following levels were established for each input:

- Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Assets or liabilities classified in Level 1 include highly liquid short-term investments, and traded commodities obtained from active exchanges such as the New York Mercantile Exchange whereby the Company can obtain quoted prices for identically traded commodities.
- Level 2: Fair value is based on inputs other than quoted prices included in Level 1, which are either directly or indirectly observable at the reporting date. Level 2 includes those assets or liabilities that are valued using commonly used valuation techniques, such as a discounted cash flow model or the Black-Scholes option pricing model. Valuation models use inputs such as quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active but observable, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument.
- Level 3: Fair value is based on unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the instrument. Level 3 includes assets or liabilities that are also valued using commonly used valuation techniques described in Level 2. However, some inputs used in the models may not be based on observable market data, but rather are based on the Company's best estimate from the perspective of a market participant.

The fair value measurement of an asset or liability is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels.

Further information about the significant assumptions made in measuring certain fair values that are considered to be key sources of estimation uncertainty, is included in the following notes:

- Note 4 – Business acquisitions;
- Notes 13 and 27 – Financial instruments;
- Note 17 – Property, plant and equipment; and
- Note 22 – Provisions.

Depreciation and amortization

Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of the life characteristics of common assets. During 2025 and 2024, management assessed the major components of existing and acquired property, plant and equipment in the respective years (see note 4) and estimated the useful lives of the respective components consistent with the Company's estimated useful lives for existing major components of similar generation facilities and equipment.

Income taxes

The Company's operations are complex, and the related domestic and foreign tax interpretations, regulations, legislation, and jurisprudence are continually changing. Income taxes are determined based on estimates of the Company's current income taxes and estimates of deferred income taxes resulting from temporary tax differences. Deferred income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. Details of tax losses expected to be utilized and the basis of utilization are provided in note 8.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Business combination:

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

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

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

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

The total purchase price of the acquisition was $3.0 billion (US$2.2 billion) in total cash consideration, including working capital and other closing adjustments, which were finalized in the fourth quarter of 2025.

The purchase price allocation reflects management's best estimate of the fair value of assets acquired and liabilities assumed based on the information obtained and analysis performed. The valuation techniques used for measuring the fair value of material assets acquired include significant estimates associated with the depreciated replacement cost approach for property, plant and equipment, which includes estimates of replacement cost and reflects adjustments for physical deterioration as well as functional and economic obsolescence.

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

	June 9, 2025
Cash and cash equivalents	$ 1
Trade and other receivables[1]	15
Inventories	15
Property, plant and equipment	3,010
Right-of-use asset	30
Other assets	2
Trade and other payables	(12)
Derivative financial instrument liabilities	(7)
Lease liabilities	(30)
Provisions	(53)
Fair value of net assets acquired	$ 2,971

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

The Company assumed a provision to return a portion of amounts previously received by Hummel Station, LLC, from the Federal Energy Regulatory Commission (FERC) for reactive supply and voltage control from generation sources service overpayments in the estimated amount of $34 million, included in provisions. The payment will be due eighteen months after final acceptance from FERC is received. Provisions also include decommissioning provisions of $19 million.

Revenues and net income from the date of acquisition to December 31, 2025, were $531 million and $192 million, respectively. If the acquisition had occurred on January 1, 2025, consolidated revenues and consolidated net income would have been $4,165 million and $290 million, respectively.

For the year ended December 31, 2025, the Company incurred acquisition costs of $43 million which were recorded on the Company's consolidated statements of income primarily as other administrative expense.

Acquisition of New Harquahala Generating Company, LLC

On February 16, 2024, Capital Power and an affiliate of a fund managed by BlackRock's Diversified Infrastructure business each acquired 50% equity interests in New Harquahala Generating Company, LLC (Harquahala), through their joint venture partnership, Trident Parent Holdings LLC. Harquahala owns a 1,092 megawatt (MW) natural gas-fired generation facility in Maricopa County, Arizona.

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

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Business combination, continued:

Acquisition of New Harquahala Generating Company, LLC, continued

Capital Power's investment for its 50% ownership of Trident Parent Holdings LLC was $310 million (US$230 million) of cash consideration, including working capital and other closing adjustments of $6 million (US$4 million). The Company previously entered into foreign exchange cash flow hedges pertaining to the hedged portion of U.S. dollar denominated funds used to acquire the equity-accounted investment which settled during the first quarter of 2024 for a loss of $6 million which was recorded as part of the equity-accounted investment balance on the statements of financial position. Capital Power is responsible for operations and maintenance and asset management for which it will receive an annual management fee.

Substantially all of the underlying assets and liabilities of Harquahala are property, plant and equipment representing the fair value of the generation facility.

Acquisition of CXA La Paloma, LLC

On February 9, 2024, the Company acquired 100% of the equity interests in CXA La Paloma, LLC (La Paloma), which owns the 1,062 MW La Paloma natural gas-fired generation facility in Kern County, California. The purchase price consisted of $910 million (US$676 million) in total cash consideration, including working capital and other closing adjustments.

The acquisition of the contracted combined-cycle U.S. gas generation facility supports the Company's strategic growth and expansion in the U.S. Western Electricity Coordinating Council region.

The valuation techniques used for measuring the fair value of material assets acquired include significant estimates associated with the depreciated replacement cost approach for property, plant and equipment and an income-based approach, the multi-period excess earning method, for the intangible assets. The depreciated replacement cost includes estimates of replacement cost and reflects adjustments for physical deterioration as well as functional and economic obsolescence. The multi-period excess earnings method considers the present value of net cash flows expected to be generated by power purchase arrangements acquired, by excluding any cash flows related to contributory assets.

La Paloma is substantially contracted with resource adequacy contracts through 2029 with multiple investment grade utilities and load serving entities.

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

	February 9, 2024
Cash and cash equivalents	$ 2
Trade and other receivables	26
Inventories	6
Right-of-use assets	5
Intangible assets	188
Property, plant and equipment	834
Trade and other payables	(114)
Lease liabilities	(5)
Provisions	(32)
Fair value of net assets acquired	$ 910

The results of operations of La Paloma are included in the Company's consolidated statements of income and statements of changes in equity from the date of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statements of financial position. Since the acquisition date, the consolidated statements of income reflect $283 million of revenues and $113 million of net income related to La Paloma for the year ended December 31, 2024.

Had the acquisition occurred at January 1, 2024, the combined entity of the Company and the La Paloma facility would have had a total of $3,706 million of revenues and $412 million of net income for the year ended December 31, 2024 In conjunction with the acquisition of La Paloma, the Company incurred $10 million (US$7 million) in acquisition costs which have been recorded on the Company's consolidated statements of income as other administrative expenses for the year ended December 31, 2024.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

5. Other income:

Year ended December 31,	**2025**	2024
Contributions and grants	**$ 11**	$ 6
Production tax credits	**76**	76
Insurance recoveries	**12**	13
Other	**6**	4
Other income	**$ 105**	$ 99

6. Expenses:

Year ended December 31,	**2025**	2024
Included in staff costs and employee benefits expense		
Share-based payments (note 26)	**$ 17**	$ 41
Post-employment defined contribution plan expense	**9**	8
Post-employment defined benefit plan expense	**3**	2
	$ 29	$ 51

7. Net finance expense:

Year ended December 31,	**2025**	2024
Interest expense		
Interest on loans and borrowings	**$ 332**	$ 270
Capitalized interest	**(40)**	(56)
Total interest expense	**292**	214
Other finance expense (income)		
Accretion on decommissioning provisions (note 22)	**13**	12
Interest on lease liabilities	**10**	9
Interest on government grants receivable	**(8)**	(9)
Other	**–**	(5)
Net finance expense	**$ 307**	$ 221

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Income tax expense:

Year ended December 31,	2025	2024
Current income tax		
Current income tax (recovery) expense	$ (9)	$ 36
Adjustments for prior periods	(38)	(5)
Total current income tax (recovery) expense	(47)	31
Deferred income tax		
Origination and reversal of temporary differences	16	173
Recognition of previously unrecognized tax benefits	–	(9)
Adjustments for prior periods	39	3
Total deferred income tax expense	55	167
Income tax expense	$ 8	$ 198

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

Year ended December 31,	2025	2024
Net income before tax	$ 167	$ 899
Income tax at the statutory rate of 23%	38	207
Increase (decrease) resulting from:		
Non-deductible expenses and non-taxable income	(3)	(5)
Amounts attributable to non-controlling interests, equity-accounted investments, and tax-equity interests	(19)	(12)
Change in unrecognized tax benefits	–	(9)
Statutory and other rate differences	(5)	20
Other	(3)	(3)
Income tax expense	$ 8	$ 198

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Income tax expense, continued:

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

Movement of deferred tax balances

	At January 1, 2025	Recognized in net income	Currency translation adjustment	Recognized directly in equity	Amounts relating to acquisition	At December 31, 2025	Deferred tax assets	Deferred tax liabilities
Property, plant and equipment	$ (977)	$ (849)	$ 136	$ –	$ (5)	$ (1,695)	$ –	$ (1,695)
Equity-accounted investments	(51)	(24)	4	3	–	(68)	–	(68)
Intangible assets and goodwill	(22)	15	(1)	–	–	(8)	37	(45)
Right-of-use assets	(24)	5	–	–	(8)	(27)	–	(27)
Derivative financial instruments	(2)	88	(10)	5	–	81	262	(181)
Government grants receivable	(67)	13	–	–	–	(54)	–	(54)
Other assets[1]	1	7	(1)	–	–	7	13	(6)
Lease liabilities	39	(6)	–	–	8	41	41	–
Deferred revenue and other liabilities	87	18	(2)	–	–	103	103	–
Provisions	99	9	(4)	–	5	109	116	(7)
Other liabilities[2]	12	4	(1)	–	–	15	16	(1)
Share issue costs and deferred financing charges	7	–	–	3	–	10	10	–
Losses carried forward	11	715	(118)	–	–	608	608	–
Deferred partnership (income) losses	50	(50)	–	–	–	–	–	–
Deferred tax (liabilities) assets	$ (837)	$ (55)	$ 3	$ 11	$ –	$ (878)	$ 1,206	$ (2,084)
Set-off of tax						$ –	$ (1,180)	$ 1,180
Net deferred tax (liabilities) assets						$ (878)	$ 26	$ (904)

	At January 1, 2024	Recognized in net income	Currency translation adjustment	Recognized directly in equity	Amounts relating to acquisition	At December 31, 2024	Deferred tax assets	Deferred tax liabilities
Property, plant and equipment	$ (755)	$ (197)	$ (20)	$ –	$ (5)	$ (977)	$ –	$ (977)
Equity-accounted investments	8	(58)	1	(2)	–	(51)	7	(58)
Intangible assets and goodwill	(30)	13	3	–	(8)	(22)	34	(56)
Right-of-use assets	(26)	1	(1)	–	2	(24)	–	(24)
Derivative financial instruments	52	(51)	4	(7)	–	(2)	176	(178)
Government grants receivable	(77)	10	–	–	–	(67)	–	(67)
Other assets[1]	5	(4)	–	–	–	1	10	(9)
Lease liabilities	37	(1)	2	–	1	39	39	–
Deferred revenue and other liabilities	37	48	2	–	–	87	87	–
Provisions	85	3	1	–	10	99	107	(8)
Other liabilities[2]	3	9	–	–	–	12	15	(3)
Share issue costs and deferred financing charges	1	–	–	6	–	7	7	–
Losses carried forward	57	(48)	2	–	–	11	11	–
Deferred partnership (income) losses	(58)	108	–	–	–	50	50	–
Deferred tax (liabilities) assets	$ (661)	$ (167)	$ (6)	$ (3)	$ –	$ (837)	$ 543	$ (1,380)
Set-off of tax						$ –	$ (517)	$ 517
Net deferred tax (liabilities) assets						$ (837)	$ 26	$ (863)

1 Includes inventories, trade and other receivables, finance lease receivables, and other assets.
2 Includes trade and other payables and loans and borrowings.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Income tax expense, continued:

Recognized tax losses carried forward

At December 31, 2025, the Company has recognized a benefit for non-capital losses carried forward of $2,812 million (2024 – $48 million). The losses carried forward include U.S. subsidiary losses of approximately $2,807 million (US$2,046 million) (2024 – $41 million (US$28 million)). The Company determined that it is probable that there will be sufficient future taxable profit to utilize the losses carried forward.

Unrecognized deferred tax assets

The Company has transferable tax credits of approximately $69 million (US$50 million) related to capital expenditures incurred to December 31, 2025 on three U.S. solar construction projects. Significant judgment is required in determining the recognition of transferable tax credits. The assessment includes the probability of sale, the availability of buyers, regulatory requirements, and the reliability of measurement. Due to these uncertainties, no benefit has been recognized.

9. 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:

Year ended December 31,	2025	2024
Income for the period attributable to shareholders	$ 160	$ 699
Preferred share dividends[1]	(28)	(34)
Earnings available to common shareholders	$ 132	$ 665
Weighted average number of common shares	150,455,368	128,902,973
Basic earnings per share	$ 0.88	$ 5.16
Weighted average number of common shares	150,455,368	128,902,973
Effect of dilutive share purchase options (note 26)	358,187	322,450
Diluted weighted average number of common shares	150,813,555	129,225,423
Diluted earnings per share	$ 0.88	$ 5.15

1 Includes preferred share dividends declared and related taxes.

10. Cash and cash equivalents:

At December 31,	2025	2024
Cash on deposit	$ 44	$ 792
Cash equivalents	75	73
	$ 119	$ 865

Included in the Company's cash and cash equivalents:

- The Company's proportionate share of its rights to cash and cash equivalents, which are restricted to use within its joint operations and tax-equity structures of $23 million (2024 – $14 million).
- As part of its collateral requirements, one of the Company's exchange counterparties updates its bank margin accounts daily, by recording fair value changes on unsettled derivative financial instruments outstanding with the Company. At December 31, 2025, cash and cash equivalents include $62 million (2024 – $69 million) related to margin posted with exchange counterparties as a result of the Company's commodity trading activity.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

11. Trade and other receivables:

At December 31,	2025	2024
Accrued revenues	$ 327	$ 292
Trade receivables	124	109
Net trade receivables	451	401
Government grants receivable (note 14)	49	58
Prepayments	56	36
Finance lease receivable	13	12
	$ 569	$ 507

Details of the movement of the allowance for doubtful accounts are provided in note 28.

12. Inventories:

At December 31,	2025	2024
Emission credits	$ 177	$ 114
Parts and other consumables	141	117
Fuel	5	4
	$ 323	$ 235

Inventories expensed upon usage for the year ended December 31, 2025 of $18 million (2024 – $35 million) were charged to energy purchases and fuel, and other raw materials and operating charges. Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date. Details of the valuation techniques used in determining the fair values are described in note 13.

13. Derivative financial instruments and hedge accounting:

The derivative instruments assets and liabilities used for risk management purposes as described in note 28 consist of the following:

	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[1]		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	

1 The Company acquired derivatives as part of the acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC (note 4) approximately equal to 179 Gigajoules of natural gas. The terms of the derivatives were reset at the acquisition date.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Derivative financial instruments and hedge accounting, continued:

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

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices dependent on which is most representative of fair value in the circumstances, in the principal market for that instrument. The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, counterparty credit risk, the Company's own credit risk and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until inputs become observable. 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. At December 31, 2025 and 2024, the Company classified financial instruments under Level 2 and Level 3 of the fair value hierarchy described in note 3.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Derivative financial instruments and hedge accounting, continued:

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

	2025		2024	
	Unrealized (losses) gains	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (24)	$ 31	$ 38	$ 19
Energy and emission allowances non-hedges	(326)	240	263	165
Interest rate cash flow hedges	4	17	(10)	14
Interest rate non-hedges	1	(1)	–	–
Foreign exchange cash flow hedges	(7)	(4)	35	–
Foreign exchange non-hedges	1	–	–	(5)

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

	2025	2024
Revenues	$ 399	$ 826
Energy purchases and fuel	(454)	(379)
Foreign exchange loss	(3)	(5)
Net finance expense	17	14

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:

At December 31,	2025
Within one year	$ 36
Between one and five years	46
After five years	9
	$ 91

14. Government grants receivable:

Clean Technology investment tax credits

Bill C-59, which includes Clean Technology ITCs, received Royal Assent on June 20, 2024. The Company applied the recognition and measurement principles of IAS 20 – *Accounting for government grants and disclosure of government assistance*, for the Clean Technology ITCs pertaining to the Halkirk 2 Wind, York Energy BESS and Goreway BESS projects. As at December 31, 2025, the Company had accrued $175 million (2024 – $151 million) to government grants receivable, income taxes recoverable, and non-current deferred revenue and other liabilities in the consolidated statements of financial position, based on eligible spending-to-date for these projects.

To be eligible for the enhanced ITC rate the legislation requires that a 10% ratio of apprentices be utilized on the project site for Red Seal trades and that a prevailing wage be paid to all covered workers, or in the case of contracted workers that reasonable efforts are taken to ensure those workers are paid a prevailing wage.

Off-coal compensation

In 2016, the Company reached an agreement with the Government of Alberta (GoA) related to the 2030 phase-out of coal-fired generation. As compensation for the capital that the Company invested in coal generating assets that would be stranded effective December 31, 2030, the Company was to receive cash payments from the Province of $52 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. This future compensation stream was recognized as a government grant, recorded within deferred revenue and other liabilities and recognized into net income over the useful lives of the related coal-fired generation assets. This deferred revenue and other liabilities balance was fully amortized at December 31, 2023. Additionally, the compensation to be received has been recognized as a government grant receivable which is drawn down as cash payments are received.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

14. Government grants receivable, continued:

Off-coal compensation, continued

In previous years, the GoA conducted an audit on the calculation of net book values driving the compensation payments and had withheld approximately $3 million from each of the payments from 2017 through 2024. The Company disputed the withholding but had reduced the amounts recorded related to the compensation stream to reflect the uncertainty around the withheld portion of the payments (reduction of approximately $2 million to the government compensation amount recorded in other income for each of the corresponding years from 2017 through 2024).

During the second quarter of 2025, the Company settled the disputed amounts with the GoA and received a cash payment of $10 million, which resulted in a decrease to the amount previously recorded of approximately $5 million, recorded in net income through loss on disposals and other transactions. The respective deferred revenue and government grant receivable amounts were likewise adjusted to reflect total payments over the 14-year term of $706 million. At December 31, 2025, the remaining government grants receivable balance relating to off-coal compensation from the GoA was $231 million.

The main conditions on the government grant include the Company agreeing to cease coal-fired emissions on or before December 31, 2030 and the Company continuing to participate in and make a minimum annual investment of $1 million in the Alberta electricity market, with a minimum total investment in the Alberta electricity market of $70 million by the end of 2030. The Company well exceeded the total required investment in Alberta and continues to make ongoing investments in its existing Alberta assets. Additional conditions include the Company supporting the local communities surrounding the coal facilities through 2030, and fulfilling its pension and other commitments to employees.

The Company achieved its off-coal milestone with the commercial operations of the Genesee Repowering project in 2024, ahead of the required 2030 phase-out.

15. Leases:

Lessor – Facilities under operating leases

The Decatur Energy and Arlington Valley power generation facilities are accounted for as assets under operating leases. At December 31, 2025, the cost of such property, plant and equipment was $1,052 million (December 31, 2024 – $1,048 million), less accumulated depreciation of $356 million (December 31, 2024 – $322 million). During 2025, lease income from these operating leases was $163 million (2024 - $156 million).

The minimum future rental payments to be received on these PPAs are:

2026	$ 129
2027	134
2028	134
2029	134
2030	135
Thereafter	194
Total	$ 860

In January 2026, subsequent to year end, 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 (note 31).

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

15. Leases, continued:

Lessee – right-of-use assets

	Land	Offices	Equipment	Total
At January 1, 2024	$ 79	$ 17	$ 22	$ 118
Additions	5	6	–	11
Depreciation	(4)	(3)	(3)	(10)
Divestiture	(6)	–	–	(6)
Foreign currency translation	4	1	–	5
At December 31, 2024	$ 78	$ 21	$ 19	$ 118
Additions	**2**	**–**	**–**	**2**
Acquisition (note 4)	**30**	**–**	**–**	**30**
Depreciation	**(5)**	**(3)**	**(3)**	**(11)**
Foreign currency translation	**(2)**	**–**	**(1)**	**(3)**
At December 31, 2025	**$ 103**	**$ 18**	**$ 15**	**$ 136**

In December 2025, the Company exercised an option to purchase the Beaufort Solar assets for $10 million (US$7 million), which were previously subject to a sale and leaseback agreement. The purchase option was included in the measurement of the lease liability and has been included in lease liability repayments (note 20).

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

16. Intangible assets and goodwill:

	Intangible work in progress	PPAs	Contract rights	Other rights	Emission credits	Software	Goodwill	Total
Cost								
At January 1, 2024	$ 111	$ 583	$ 88	$ 167	$ 109	$ 58	$ 35	$ 1,151
Additions	17	–	–	–	13	–	–	30
Additions into service	(118)	–	–	114	–	4	–	–
Retirements and other disposals	–	–	–	–	(176)	–	–	(176)
Acquisition	–	91	–	–	97	–	–	188
Transfers to held for sale emission credits inventories	–	–	–	–	(2)	–	–	(2)
Other	–	14	5	6	4	–	–	29
At December 31, 2024	$ 10	$ 688	$ 93	$ 287	$ 45	$ 62	$ 35	$ 1,220
Additions	**6**	**–**	**–**	**–**	**13**	**–**	**–**	**19**
Additions into service	**(4)**	**–**	**–**	**3**	**–**	**1**	**–**	**–**
Retirements and other disposals	**–**	**(57)**	**–**	**–**	**(46)**	**–**	**–**	**(103)**
Other	**–**	**(6)**	**(3)**	**(3)**	**(2)**	**–**	**–**	**(14)**
At December 31, 2025	**$ 12**	**$ 625**	**$ 90**	**$ 287**	**$ 10**	**$ 63**	**$ 35**	**$ 1,122**
Accumulated amortization								
At January 1, 2024	$ –	$ (270)	$ (31)	$ (36)	$ –	$ (39)	$ –	$ (376)
Amortization	–	(76)	(4)	(8)	–	(5)	–	(93)
Other	–	(5)	(1)	(1)	–	–	–	(7)
At December 31, 2024	$ –	$ (351)	$ (36)	$ (45)	$ –	$ (44)	$ –	$ (476)
Amortization	**–**	**(68)**	**(5)**	**(9)**	**–**	**(4)**	**–**	**(86)**
Retirements and other disposals	**–**	**57**	**–**	**–**	**–**	**–**	**–**	**57**
Other	**–**	**1**	**1**	**1**	**–**	**–**	**–**	**3**
At December 31, 2025	**$ –**	**$ (361)**	**$ (40)**	**$ (53)**	**$ –**	**$ (48)**	**$ –**	**$ (502)**
Net book value								
At January 1, 2024	$ 111	$ 313	$ 57	$ 131	$ 109	$ 19	$ 35	$ 775
At December 31, 2024	$ 10	$ 337	$ 57	$ 242	$ 45	$ 18	$ 35	$ 744
At December 31, 2025	**$ 12**	**$ 264**	**$ 50**	**$ 234**	**$ 10**	**$ 15**	**$ 35**	**$ 620**

Contract rights include acquired management and operations agreements and an agreement whereby the Company sells RECs produced by Halkirk 1 Wind to a third party.

Other rights include the cost of land lease agreements for use in wind and solar power projects, and pipeline access rights relating to Arlington Valley.

Goodwill impairment testing

As part of the Company's annual impairment testing, the East Windsor CGU, which contains all of the Company's goodwill, was tested for impairment and the carrying amount of the East Windsor CGU falls within range of the estimated recoverable amount, estimated using the fair value less costs of disposal approach, for both the 2025 and 2024 annual impairment tests. As such, no impairments were required for the East Windsor CGU.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

17. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
At January 1, 2024	$ 1,206	$ 147	$ 8,182	$ 9,535
Additions	1,226	2	37	1,265
Additions into service	(1,584)	1	1,583	–
Retirements and other disposals	(3)	(1)	(607)	(611)
Acquisition	11	18	805	834
Divestiture (note 30)	(1)	(1)	(725)	(727)
Revisions to decommissioning costs (note 22)	–	–	(25)	(25)
Foreign currency translation	8	–	233	241
At December 31, 2024	$ 863	$ 166	$ 9,483	$ 10,512
Additions	**712**	**–**	**18**	**730**
Additions into service	**(822)**	**6**	**816**	**–**
Retirements and other disposals	**(8)**	**–**	**(22)**	**(30)**
Acquisition (note 4)	**23**	**2**	**2,985**	**3,010**
Revisions to decommissioning costs (note 22)	**–**	**–**	**62**	**62**
Foreign currency translation	**(10)**	**(1)**	**(145)**	**(156)**
At December 31, 2025	**$ 758**	**$ 173**	**$ 13,197**	**$ 14,128**
Accumulated depreciation				
At January 1, 2024	$ –	$ –	$ (2,978)	$ (2,978)
Depreciation	–	–	(400)	(400)
Retirements and other disposals	–	–	602	602
Divestiture (note 30)	–	–	370	370
Foreign currency translation	–	–	(45)	(45)
At December 31, 2024	$ –	$ –	$ (2,451)	$ (2,451)
Depreciation	**–**	**–**	**(483)**	**(483)**
Retirements and other disposals	**–**	**–**	**26**	**26**
Foreign currency translation	**–**	**–**	**33**	**33**
At December 31, 2025	**$ –**	**$ –**	**$ (2,875)**	**$ (2,875)**
Net book value				
At January 1, 2024	$ 1,206	$ 147	$ 5,204	$ 6,557
At December 31, 2024	$ 863	$ 166	$ 7,032	$ 8,061
At December 31, 2025	**$ 758**	**$ 173**	**$ 10,322**	**$ 11,253**

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are provided in note 7. The average borrowing rate used to capitalize interest during the year was 5.3% (2024 – 5.4%) for projects financed using general borrowings. For the years ended December 31, 2025 and 2024, there were no projects financed using specific borrowings that were included as part of property, plant and equipment.

Restrictions on assets

Details of charges over land, plant and equipment are provided in note 19.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

18. Trade and other payables:

At December 31,		**2025**		2024
Operating accruals[1]	**$**	**395**	$	427
Trade payables		**216**		163
Dividends payable		**108**		91
Accrued interest		**70**		70
	$	**789**	$	751

1 During the fourth quarter of 2024, the Company completed a strategic organizational review to optimize the organization to scale and grow efficiently, inclusive of decentralizing corporate functions, reducing headcount in certain areas and expanding in key growth areas. In connection with the restructuring, the Company incurred total costs of $49 million of which $39 million was recorded within operating accruals and $10 million within provisions.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

19. Loans and borrowings:

	Effective interest rate	December 31, 2025	December 31, 2024
Unsecured senior medium-term notes, payable semi-annually			
Issued by CPC, at 4.99% due in 2026	5.07%	–	300
Issued by CPC, at 5.38% due in 2027	5.49%	400	400
Issued by CPC, at 5.82% due in 2028	5.96%	350	350
Issued by CPC, at 4.42% due in 2030	4.49%	275	275
Issued by CPC, at 4.83% due in 2031	4.92%	600	600
Issued by CPC, at 3.15% due in 2032	3.21%	350	350
Issued by CPC, at 4.23% due in 2033	4.33%	600	–
Issued by CPC, at 5.97% due in 2034	6.05%	450	450
		3,025	2,725
CPC private placement, payable semi-annually			
Issued by CPC, at 3.85% due in 2026	3.85%	160	160
Issued by CPC, US$700, at 5.26% due in 2028	5.54%	960	–
Issued by CPC, at 4.56% due in 2029	4.64%	210	210
Issued by CPC, at 4.72% due in 2031	4.79%	65	65
Issued by CPC, US$150, at 3.24% due in 2033	3.29%	206	216
Issued by CPC, at 4.96% due in 2034	5.02%	50	50
Issued by CPC, US$500, at 6.19% due in 2035	6.30%	686	–
		2,337	701
CPLP unsecured senior notes, payable semi-annually			
US$65, at 5.61% due in 2026	5.67%	89	93
		89	93
Subordinated notes, payable semi-annually			
Issued by CPC, at 8.13%, due in 2054	8.21%	450	450
Issued by CPC, at 7.95%, due in 2082	8.08%	350	350
		800	800
CPLP non-recourse financing, payable quarterly			
Goreway Power Station, $564 at floating rates, due in 2027	5.63%	–	330
East Windsor Cogeneration Project, at 6.28%, due in 2029	6.23%	58	71
Macho Springs, US$50 at 6.90%, due in 2031	7.00%	29	35
		87	436
Tax-equity financing, payable quarterly[1]			
Bloom Wind, US$41		30	53
New Frontier Wind, US$31		26	42
Cardinal Point Wind, US$77		86	107
Buckthorn Wind, US$39		38	55
Committed credit facilities		254	–
		434	257
Total debt payable		6,772	5,012
Less: current portion		347	157
		6,425	4,855
Less: deferred debt issue costs		42	36
		$ 6,383	$ 4,819

1 Effective interest rates on tax-equity financing reflect the internal rates of return on the respective tax-equity investments ranging from 6.50% to 8.95%.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

19. Loans and borrowings, continued:

$600 million medium-term notes (2025)

On November 14, 2025, the Company closed a public offering of unsecured medium-term notes in the aggregate principal amount of $600 million. The notes have an interest rate of 4.231% and mature on January 14, 2033. The Company used the net proceeds to redeem the $300 million 4.986% medium-term notes due January 23, 2026 as well as repay Goreway project debt.

Private offering of senior notes

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

$600 million medium-term notes (2024)

On September 16, 2024, the Company closed a public offering of unsecured medium-term notes, in the aggregate principal amount of $600 million. The notes have a coupon rate of 4.831% and mature on September 16, 2031.

$450 million subordinated notes

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

Non-recourse financing

East Windsor Cogeneration Project financing represents Series 1 Senior bonds issued by the Company. The debt is secured by a charge against project assets which have a carrying amount of $115 million.

Macho Springs financing represents loans for the project. The debt is secured by a charge against project assets which have a carrying amount of $40 million.

Tax-equity financing

Tax-equity financing represents the initial equity investments made by the project investors, on the respective projects, adjusted for earnings, tax benefits and cash distributions paid to date. The maturity dates of these obligations are subject to change and are driven by the dates on which the project investors reach the agreed upon target rates of return on the respective projects.

Committed credit facilities

On August 8, 2025, the Company entered into a 2-year revolving credit agreement with a total commitment of $600 million, maturing in 2027. The funds can be drawn in Canadian or U.S. dollars. Interest is floating and is based on the type of draw, plus margin. At December 31, 2025, $254 million (US$185 million) of the facility was drawn, payable in U.S. funds with an average interest rate was 5.21%.

On June 6, 2025, the Company amended the terms of its unsecured syndicated credit facility and terminated its $300 million unsecured club credit facility. The amendments to the syndicated credit facility included an increase to the maximum principal amount from $700 million to $1.5 billion, an extension of one year to June 2030, and a change to the modified consolidated net tangible assets to consolidated net tangible assets ratio covenant to be based on total assets rather than net tangible assets. At December 31, 2025, there were no amounts drawn (2024 – no amounts drawn) and there were no amounts drawn at the time of the amendment.

Under the terms of the syndicated credit facility, the Company's subsidiaries may obtain advances by way of Canadian or U.S. prime loans, U.S. base rate loans, U.S. SOFR loans and CORRA loans. Amounts drawn by way of prime or base rate loans each bear interest at the prevailing Canadian Prime, U.S. Prime, or U.S. base rate respectively, plus a spread ranging from 0.2% to 1.5%, depending on the Company's credit rating. Amounts drawn by way of U.S. SOFR loans or CORRA loans bear interest at the prevailing SOFR rate or CORRA rate plus a spread ranging from 1.2% to 2.5%, depending on the Company's credit rating.

On April 14, 2025, in anticipation of the acquisition (note 4), the Company entered into a commitment letter with TD Securities Inc. for fully underwritten $2 billion senior unsecured term loans. As the Company amended the terms of its syndicated credit facility, the commitment letter was no longer required and has been terminated.

Bilateral unsecured demand credit facilities are available to Capital Power and include $1,402 million for the issuance of letters of credit and a further $25 million in general facilities. The general facilities are undrawn at December 31, 2025 and 2024 while letters of credit of $604 million (2024 – $608 million) have been issued as described in note 31.

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 December 31, 2025, $99 million of bonds were issued under these facilities (2024 – $99 million).

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

20. Reconciliation of movements of liabilities to cash flows from financing activities:

	2025	2024
Loans and borrowings[1]		
At January 1	$ 4,976	$ 4,716
Proceeds from issue of loans and borrowings (note 19)	2,506	1,050
Repayments	(650)	(781)
Deferred debt issue costs	(18)	(9)
Total changes from financing cash flows	1,838	260
Effect of changes in foreign exchange rates	(32)	51
Non-cash repayments on tax-equity financing (note 5)	(76)	(76)
Implicit interest on tax-equity financing	15	19
Other non-cash items	9	6
Total other changes	(84)	–
At December 31,	$ 6,730	$ 4,976

1 Includes deferred debt issue costs.

	2025	2024
Lease liabilities[2]		
At January 1	$ 151	$ 147
Repayments (note 15)	(28)	(16)
Interest on lease liabilities (note 7)	10	9
Total changes from financing cash flows	(18)	(7)
Additions	2	6
Additions through business acquisitions (note 4)	30	5
Divestiture (note 30)	–	(6)
Effects of changes in foreign exchange rates	(3)	6
Total other changes	29	11
At December 31,	$ 162	$ 151

2 Includes the current portion disclosed within current deferred revenue and other liabilities.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

21. Deferred revenue and other liabilities:

At December 31,	2025	2024
Deferred payments on capital project costs	$ 142	$ 290
Contract liabilities[1]	29	33
Other deferred revenue and liabilities	235	213
	406	536
Less current portions:		
Contract liabilities[1]	3	4
Deferred payments on capital project costs	46	48
Deferred payments on capital project costs – supplier finance arrangement[2]	31	130
Other deferred revenue and liabilities	33	31
Total current deferred revenue and other liabilities	113	213
	$ 293	$ 323

1 During the year ended December 31, 2025 $4 million (2024 – $3 million) was recognized as revenues in relation to outstanding contract liabilities settled during the year.

2 Relates to the Company's supplier finance arrangement for expenditures on Halkirk 2 Wind under which the Company has agreed to a scheduled payment of their invoices from a finance provider. Under the agreement, the finance provider agrees to pay amounts due to the participating supplier in respect of invoices owed by the Company and the Company repays the finance provider up to 360 days after the invoice due dates, at the discretion of the Company. During 2025, payments of $124 million have been made to the finance provider. The purpose of this agreement is to facilitate payment processing and provide the supplier with agreed upon payment terms, compared with the related invoice payment due dates. The deferred payments under the arrangement are classified as current at December 31, 2025 and 2024.

22. Provisions:

	Decommissioning	Employee benefits[1]	Other	Total
At January 1, 2025	$ 346	$ 112	$ –	$ 458
Additional liabilities incurred	45	40	33	118
Liabilities assumed in business acquisition (note 4)	19	–	34	53
Liabilities settled	(37)	(47)	–	(84)
Foreign currency translation	(5)	–	1	(4)
Change in discount rate	(16)	–	–	(16)
Increase in decommissioning costs	78	–	–	78
Accretion (note 7)	13	–	–	13
At December 31, 2025	$ 443	$ 105	$ 68	$ 616
Non-current	415	51	38	504
Current	28	54	30	112
	$ 443	$ 105	$ 68	$ 616

1 Included in the employee benefits provision is $46 million pertaining to the share-based payment obligations described in note 26, of which $33 million is vested at December 31, 2025 (2024 – $54 million total share-based payment obligation, $33 million vested).

Decommissioning provisions

The Company has recorded decommissioning provisions for its power generation facilities and the Genesee coal mine (the Genesee Mine) as it is obligated to remove the facilities at the end of their useful lives and restore the power facilities and mine sites to their original condition. In the fourth quarter of 2023, the Genesee Mine ceased mining. The decommissioning provision for the Genesee Mine was incurred over time as new areas were mined, and a portion of the liability was settled over time as areas were reclaimed prior to final pit reclamation.

At December 31, 2025, the Company's estimate of the undiscounted cash flows required to settle its decommissioning obligations is approximately $1,084 million (2024 – $717 million), calculated using an inflation rate of 2% (2024 – 2%). The expected timing for settlement of the obligations is between 2026 and 2061, which reflects reclamation of areas of the Genesee Mine and the anticipated useful lives of our power generation facilities.

The payments to settle the obligations are expected to occur between 2026 and 2061 for the power generation facilities. The payments to settle the obligations are expected to occur between 2026 and 2028 for unreclaimed sections of the Genesee Mine that were mined. Discount rates used to calculate the carrying amount of the obligations range from 2.43% to 4.81%. The actual net costs to settle decommissioning obligations may change due to the timing of retirement and reclamation activities, and changes in the cost of labour, materials and contractor rates. Changes in environmental regulations, including requirements that may evolve as energy transition policies develop, could also change the nature, timing, or extent of remediation monitoring activities required.

The increase in decommissioning costs during 2025 reflect evolving estimation methodologies and regulations around renewable energy facilities and was largely attributable to the Company's wind facilities. Additional liabilities incurred reflect decommissioning estimates for Bear Branch, Hornet, and Maple Leaf solar projects as construction progressed, as well as for the York and Goreway BESS facilities commissioned during 2025.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

23. Share capital:

Authorized shares

	Number of shares authorized
Common shares, with no par value	unlimited
Unlimited preference shares, issuable in series:	
Series 1 and 2	5 million
Series 3 and 4	6 million
Series 5 and 6	8 million
Special limited voting shares[1]	two

1 The special limited voting shares entitle holders the right to vote as a class on any matter that would: (i) change the location of Capital Power's head office to a place other than The City of Edmonton in the Province of Alberta; (ii) amend the articles of Capital Power to, or result in a transaction that would, in each case, impact the location of the head office or its meaning as defined in Capital Power's articles; or (iii) amend the rights attaching to the special limited voting shares. Subsequent to year end, the Company retired its special limited voting shares in consideration of cash payments totaling $75 million, comprised of $40 million payable in the first quarter of 2026 and $35 million payable in 2027. Concurrently, the Company entered into a 10-year agreement with the City of Edmonton which includes obligations regarding the head office.

Issued and fully paid shares

	Common shares		Preference shares	
	Number of shares	Amount	Number of shares	Amount
At January 1, 2024	117,682,621	$ 2,921	25,000,000	$ 603
Shares issued	18,796,000	860	–	–
Share issue costs	–	(35)	–	–
Deferred taxes on share issue	–	8	–	–
Share purchase options exercised (note 26)	827,930	27	–	–
Dividend reinvestment plan	1,672,877	67	–	–
Preferred share redemption[2]	–	–	(6,000,000)	(150)
At December 31, 2024	138,979,428	$ 3,848	19,000,000	$ 453
Shares issued[1]	**15,357,500**	**667**	**–**	**–**
Share issue costs[1]	**–**	**(28)**	**–**	**–**
Deferred taxes on share issue	**–**	**7**	**–**	**–**
Share purchase options exercised (note 26)	**273,867**	**10**	**–**	**–**
Dividend reinvestment plan	**1,352,104**	**79**	**–**	**–**
At December 31, 2025	**155,962,899**	**$ 4,583**	**19,000,000**	**$ 453**

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

2 On June 30, 2024, the Company redeemed all of its 6 million issued and outstanding 5.75% cumulative rate reset preference shares, Series 11. The quarterly dividend for the second quarter of 2024 was the final quarterly dividend on the Series 11 shares and was paid on the redemption date.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

23. Share capital, continued:

Cumulative rate reset preference shares

Preferred shares	Dividend per share per annum[3]	Dividend rate reset[4]	Redemption and Conversion option date[5,6]	Right to convert into[6]
Series 1	$1.240	Reset to $1.240 from $0.655 per annum effective December 31, 2025 for the March 31, 2026 dividend payment.	December 31, 2030	Series 2
Series 3	$1.715	Reset to $1.715 from $1.363 per annum effective December 31, 2023 for the March 31, 2024 dividend payment.	December 31, 2028	Series 4
Series 5	$1.658	Reset to $1.658 from $1.125 per annum effective June 30, 2023 for the September 30, 2023 dividend payment.	June 30, 2028	Series 6

3 Dividend rate per annum – Holders of Series 1, Series 3, and Series 5 shares will be entitled to receive fixed cumulative quarterly dividends that yield 4.96%, 6.86%, and 6.63%, respectively, per annum payable on the last business day of March, June, September, and December of each year, as and when declared by the Board of Directors of Capital Power.

4 Dividend rate reset terms – Dividend rates on Series 1, Series 3, and Series 5 shares will be reset every five years following the issuance date or most recent rate reset date at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.17%, 3.23%, and 3.15% respectively, as and when declared by the Board of Directors of Capital Power.

5 Redemption option date and terms – Series 1, Series 3, and Series 5 shares are redeemable by Capital Power, at its option, on the redemption date and every five years thereafter.

6 Conversion option date – Holders of Series 1, Series 3, and Series 5 shares will have the right, at their option, on the conversion date and every five years thereafter, to convert all or any part of their shares into Cumulative Floating Rate Preference Shares Series 2, Series 4, and Series 6, respectively, subject to certain conditions. Conversion terms – Holders of Series 2, Series 4, and Series 6 shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, 3.23%, and 3.15% respectively, as and when declared by the Board of Directors of Capital Power.

Common and preferred share dividends

The common and preferred share dividends declared and paid by the Company for the years ended December 31, 2024 and 2023 are summarized as follows:

	Dividends declared				Dividends paid			
	2025		2024		**2025**		2024	
	Per share	**Total**	Per share	Total	**Per share**	**Total**	Per share	Total
Common[7,8]	**$ 2.6858**	**$ 407**	$ 2.5338	$ 335	**$ 2.6467**	**$ 390**	$ 2.4969	$ 316
Preference:								
Series 1	**0.6553**	**3**	0.6553	3	**0.6553**	**3**	0.6553	3
Series 3	**1.7151**	**11**	1.7151	11	**1.7151**	**11**	1.7151	11
Series 5	**1.6577**	**13**	1.6577	13	**1.6577**	**13**	1.6577	13
Series 11[2]	**–**	**–**	0.7188	4	**–**	**–**	0.7188	4

7 On July 29, 2025, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $0.6519 per common share to $0.6910 per common share effective for the third quarter of 2025.

8 For the year ended December 31, 2025 common dividends paid consist of $311 million paid in cash and $79 million through the Company's dividend re-investment plan (December 31, 2024 – $249 million paid in cash and $67 million through the Company's dividend re-investment plan).

24. Change in non-cash operating working capital:

Year ended December 31,	**2025**	2024
Trade and other receivables	**$ (26)**	$ 194
Inventories	**(82)**	77
Trade and other payables	**96**	(58)
Deferred revenue and other liabilities	**36**	(5)
Provisions	**(31)**	(35)
	$ (7)	$ 173

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

25. Related party balances and transactions:

Nature of transactions

As described in note 30, the Company is party to a number of joint arrangements, primarily for the construction and operation of power generating facilities. The joint arrangements provide energy to the Company and the Company provides management and operation services to the joint arrangements. Transactions with joint arrangements are eliminated to the extent of the Company's interest in the joint arrangement. For the years ended December 31, 2025 and December 31, 2024 non-eliminated amounts due to joint ventures were $18 million and $nil, respectively, and non-eliminated amounts due from joint ventures were $9 million and $5 million, respectively.

Compensation of key management personnel

Year ended December 31,		**2025**		2024
Short-term employee benefits	**$**	**7**	$	8
Share-based payments		**5**		11
	$	**12**	$	19

Key management personnel include certain executive officers of the Company in addition to the directors of the Company.

26. Share-based payments:

Share purchase options

Under the Company's long-term incentive plan, the Company provides share purchase options to certain employees to purchase common shares, provided that the number of shares reserved for issuance will not exceed 10% of the common shares to be outstanding at closing and that the aggregate number of shares issued by the Company under this plan will not exceed 11,194,506 common shares. Granted options vest over a three-year period and may be exercised within 7 years of the grant date.

The following illustrates share purchase options activity during the years ended December 31, 2025 and 2024:

	2025			2024		
	Number of options		**Weighted average exercise price**	Number of options		Weighted average exercise price
Options outstanding, at January 1	**1,220,262**	**$**	**37.65**	1,736,821	$	33.78
Granted	**299,079**	**$**	**52.06**	384,021	$	37.81
Exercised[1]	**(273,867)**	**$**	**34.92**	(827,930)	$	29.40
Forfeited	**–**	**$**	**–**	(37,296)	$	39.79
Expired	**(47,220)**	**$**	**40.40**	(35,354)	$	40.36
Options outstanding, at December 31,	**1,198,254**	**$**	**41.49**	1,220,262	$	37.65
Vested options outstanding, at December 31,	**782,161**	**$**	**38.60**	550,958	$	35.21

1 The weighted average share price at the date of exercise was $61.58 (2024 – $47.19).

The following assumptions were used in estimating the fair value of the granted share purchase options:

	Share purchase options issued in:			
		2025		2024
Share price at grant date	**$**	**52.06**	$	37.81
Weighted average fair values at grant date	**$**	**6.57**	$	3.32
Expected volatility		**20.80%**		17.40%
Expected option life		**4.5 years**		4.5 years
Expected dividend yield		**5.009%**		6.506%
Risk-free interest rate		**2.92%**		3.12%
Exercise price	**$**	**52.06**	$	37.81
Expiry date		**May 7, 2032**		March 15, 2031

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

26. Share-based payments, continued:

Share purchase options, continued

During the year ended December 31, 2025, the Company recorded compensation expense of $1 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2024 – $1 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options at December 31, 2025 is 4.45 years (2024 – 4.55 years). The exercise prices of share purchase options outstanding at December 31, 2025 range from $30.78 to $52.06 (2024 – $24.47 to $42.45).

Performance share units

Capital Power grants performance share units (PSUs) to certain employees, which make those employees eligible to receive cash payments based on an equivalent number of common shares at a specified release date for an amount based on the 30-day volume-weighted average price (VWAP) of such number of common shares on the release date. PSUs are fully vested three years from the grant date and vest as service is rendered over that three-year period. Payments are based on the number of units vested including dividend equivalents, with the total number of units adjusted for a factor ranging from 0% to 200% based on two objectives: the Company's share price performance relative to a group of peer organizations, as determined by comparing total shareholder return, weighted at 80%; and, certain sustainability linked metrics, weighted at 20%.

Restricted share units

Capital Power grants restricted share units (RSUs) to certain employees, which make those employees eligible to receive cash payments based on an equivalent number of common shares, including dividend equivalents, at a specified release date for an amount based on the 30-day VWAP of such number of common shares on the release date. RSUs are fully vested three years from the grant date and vest as service is rendered over that three-year period.

Deferred share units

The Company has approved a deferred share unit (DSU) Plan pursuant to which non-employee directors or executives of the Company may receive their annual equity retainer or their Short-Term Incentive award, respectively, in the form of DSUs. Directors are entitled to elect to receive their annual retainer, committee retainer, and/or committee chair retainer in full or partial DSUs. Executives who are not yet in compliance with their share ownership requirements may elect to defer all or a portion of their Short-Term Incentive award in the form of DSUs. Directors and executives will receive additional DSUs in respect of dividends payable on an equivalent number of common shares of the Company on the recognized record date. DSUs vest immediately and may be redeemed for cash no earlier than six months after a director's resignation from the Board of Directors or no earlier than the executive's resignation from the Company and no later than December 15th of the year following their resignation. The payout uses the volume-weighted average closing price of the Company's common shares on the Toronto Stock Exchange for the five trading days immediately before the redemption date.

The following illustrates the PSU, RSU, and DSU activity during the years ended December 31, 2025 and 2024:

	PSUs		RSUs		DSUs	
	2025	2024	**2025**	2024	**2025**	2024
Outstanding, at January 1	**352,431**	328,926	**293,096**	285,934	**230,006**	291,074
Granted[2]	**102,108**	125,729	**101,316**	108,484	**26,114**	40,053
Released[3]	**(206,609)**	(201,519)	**(128,844)**	(98,288)	**(33,834)**	(118,402)
Dividend equivalents	**14,512**	21,383	**11,859**	18,385	**10,178**	17,281
Added by Performance Factor	**87,672**	96,432	**–**	–	**–**	–
Forfeited	**(13,692)**	(18,520)	**(13,927)**	(21,419)	**–**	–
Outstanding, at December 31,	**336,422**	352,431	**263,500**	293,096	**232,464**	230,006

2 The fair value of the PSUs at the grant date was $48.08 (2024 – $37.47), the fair value of the RSUs at the grant date was $48.08 (2024 – $37.47), and the fair value of the DSUs at the grant date was $57.95 (2024 – $42.98)

3 The weighted average share price of PSUs at the date of release was $61.92 (2024 – $37.71), the weighted average share price of RSUs at the date of release was $61.20 (2024 – $38.18), and the weighted average share price of DSUs at the date of release was $56.03 (2024 - $46.26).

During the year ended December 31, 2025, the Company recorded a compensation expense of $9 million (2024 – $21 million) related to the PSUs, $6 million (2024 – $9 million) related to the RSUs, and $1 million (2024 – $10 million) relating to the DSUs in staff costs and employee benefits expense.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

27. 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:

		December 31, 2025		December 31, 2024	
	Fair value hierarchy level	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Financial assets[1]					
Government grants receivable (note 14)[2]	Level 2	**$ 406**	**$ 389**	$ 438	$ 400
Financial liabilities[1]					
Loans and borrowings (note 19)[3]	Level 2	**$ 6,730**	**$ 7,052**	$ 4,976	$ 5,244

1 Includes current portion.
2 The fair value of the Company's government grants receivable held at amortized cost is estimated by discounting its expected future cash flows at current market interest rates for comparable instruments with similar terms, plus an estimated credit spread based on the counterparty credit risk at December 31, 2025 and 2024.
3 The fair values of the Company's loans and borrowings are based on determining a current yield for the Company's loans and borrowings at December 31, 2025 and 2024. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's loans and borrowings. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

Fair value hierarchy

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

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in note 3.

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

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

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

27. Financial instruments, continued:

Fair value hierarchy, continued

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:

at December 31,	2025	2024
REC pricing (per certificate) – Solar	**$3 to $25**	$3 to $201
REC pricing (per certificate) – Wind	**$3 to $5**	$3 to $8
Forward power pricing (per MWh) – Solar	**$21 to $179**	$15 to $113
Forward power pricing (per MWh) – Wind	**$18 to $101**	$15 to $142
Average monthly notional generation (MWh) – Solar	**6,537 to 13,018**	6,554 to 13,044
Average monthly notional generation (MWh) – Wind	**17,703 to 59,308**	16,540 to 60,060

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

At December 31,	2025	2024
REC pricing (per certificate) – Solar	**$ 3**	$ 2
REC pricing (per certificate) – Wind	**$ 2**	$ 4
Forward power pricing (MWh) – Solar	**$ 22**	$ 4
Forward power pricing (MWh) – Wind	**$ 42**	$ 59
Generation – Solar	**7**	4
Generation – Wind	**11**	13

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:

At December 31,	2025	2024
At January 1[1]	**$ (156)**	$ (297)
Additions	**(12)**	27
(Losses) gains included in net income[2]	**(153)**	137
Settlements	**44**	(15)
Transfers[3]	**(1)**	1
Foreign exchange gains (losses)	**10**	(9)
At end of period	**$ (268)**	$ (156)

1 The fair value of derivative instruments assets and liabilities are presented on a net basis.
2 Recorded in revenues.
3 Relates to transfers from Level 3 to Level 2 when pricing inputs become readily observable. There were no transfers from Level 2 to Level 3.

Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. 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.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

27. Financial instruments, continued:

Offsetting of financial assets and liabilities

The Company's commodity trading transactions are typically transacted on an exchange or under International Swap Dealers Association (ISDA) Master Agreements or similar master agreements. In general, under the Company's trading agreements the amounts owed by each counterparty that are due on a single day in respect of all transactions outstanding in the same currency under the agreement are aggregated into a single net amount being payable by one party to the other. Such amounts meet the criteria for offsetting and are presented as such in the Company's statements of financial position.

The Company issues and accepts collateral in the form of cash and letters of credit in respect of its commodity trading transactions. Such collateral is generally subject to standard industry terms. The terms generally also give each counterparty the right to terminate the related transactions upon the counterparty's failure to post collateral.

Financial assets and liabilities subject to offsetting, enforceable master netting arrangements or similar arrangements

				Related amounts not offset in the statement of financial position		
Types of financial assets and liabilities	Gross amounts recognized	Gross amounts offset in the statement of financial position	Net amounts presented in the statement of financial position[4]	Financial instruments	Collateral received/pledged[5]	Net amount
At December 31, 2025						
Commodity trading assets	**$ 1,383**	**$ (273)**	**$ 1,110**	**$ (474)**	**$ (46)**	**$ 590**
Commodity trading liabilities	**$ 1,675**	**$ (273)**	**$ 1,402**	**$ (474)**	**$ (216)**	**$ 712**
At December 31, 2024						
Commodity trading assets	$ 1,006	$ (241)	$ 765	$ (216)	$ (49)	$ 500
Commodity trading liabilities	$ 909	$ (241)	$ 668	$ (217)	$ (83)	$ 368

4 The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $314 million (2024 – $236 million), non-current derivative instruments assets of $369 million (2024 – $410 million) and trade and other receivables of $427 million (2024 – $119 million). The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $273 million (2024 – $140 million), non-current derivative instruments liabilities of $718 million (2024 – $485 million) and trade and other payables of $411 million (2024 – $43 million).

5 Collateral received relating to the net financial assets disclosed above is in the form of letters of credit received from the Company's counterparties.

28. Risk management:

Risk management overview

The Company is exposed to a number of financial risks arising from business activities and its use of financial instruments, including market risk, credit risk and liquidity risk. The Company's overall risk management process is designed to identify, manage and mitigate business risks which include, among other risks, financial risk. Risk management is overseen by the Company's Executive Team according to objectives, targets, and policies approved by the Capital Power Board of Directors. The Executive Team is comprised of the most senior management group within the Company.

Risk management strategies, policies, and limits are designed to help ensure risk exposures are managed within the Company's business objectives and risk tolerance. The Company's financial risk management objective is to protect and limit volatility in net income and cash flows.

Commodity price risk management and the associated credit risk management are carried out in accordance with the respective commodity, credit, and financial exposures risk management policies, as approved by the Executive Team and the Board of Directors. Financial risk management, including foreign exchange risk, interest rate risk, and liquidity risk, is carried out by a centralized Treasury function, also in accordance with financial risk management policies approved by the Executive Team and the Board of Directors. Capital Power's Audit Committee of the Board of Directors, in its oversight role, monitors the assessment of financial risk management controls and procedures to ensure compliance with applicable policies.

Market risk

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates and equity prices. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Company's financial assets and liabilities held, non-trading physical asset and contract portfolios, and trading portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps (or contracts-for-differences), and option contracts. Such derivative instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Commodity risk exposures are monitored daily against approved risk limits, and control processes are in place to monitor that only authorized activities are undertaken.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

28. Risk management, continued:

Market risk, continued

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of income on these contracts. The Company's actual exposure to market risks is constantly changing as the Company's portfolio of debt, foreign currency and commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Company.

Commodity price risk

The Company is exposed to commodity price risk as part of its normal business operations, including energy procurement activities in Canada and the U.S. The Company's energy procurement activities consist of power generation, non-market traded and market traded electricity, natural gas and emission credits purchase and sales contracts, and derivative contracts. The Company is primarily exposed to changes in the prices of electricity and natural gas. The Company actively manages commodity price risk by optimizing its asset and contract portfolios utilizing the following methods:

- reducing exposure to the volatility of commodity prices related to electricity sales and natural gas purchases by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration,
- entering into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices, including entering into long-term tolling arrangements whereby variable changes linked to the price of natural gas are assumed by the counterparty, and
- entering into back-to-back electricity and natural gas physical and financial contracts to lock in a margin.

The Company also engages in taking market risk positions within authorized limits approved by Capital Power's Executive Team and Board of Directors. The trading portfolio includes electricity and natural gas physical and financial derivative contracts which are transacted with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities.

The Company employs a Value-at-Risk (VaR) methodology to manage aggregate risk exposures to commodity prices from its trading and asset portfolios on a consolidated basis. VaR measures the estimated potential loss in a portfolio of positions associated with the movement of commodity prices for a specified period and a given confidence level. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market price volatilities and risk diversification by recognizing offsetting positions and correlations between products and markets. This technique makes use of historical data and assesses the market risk arising from possible future changes in commodity prices over the holding period. Capital Power's VaR uses a statistical confidence level of 99% over a 10-business-day holding period. This measure reflects a 1% probability that, over the 10-day period commencing with the point in time that the VaR is measured, the fair value of the overall commodity portfolio could decrease by an amount in excess of the VaR amount. As VaR is not a perfect predictor of risk, the Company can neither guarantee that losses will not exceed the VaR nor that losses in excess of the VaR will not occur more frequently than 1% of the time.

VaR should be interpreted considering the limitations of the methodologies used, including:

- VaR calculated based on a holding period may not fully capture the market risk of positions that cannot be liquidated or hedged within the holding period,
- VaR is computed at the close of business and positions may change substantially during the day, and
- VaR, at a 99% confidence level, does not reflect the extent of potential losses beyond that percentile; losses on the other 1% of occasions could be substantially greater than the estimated VaR.

At December 31, 2025, the VaR of the Company's commodity trading and assets portfolios as a result of unfavourable market price changes was $38 million (2024 – $38 million).

Foreign exchange risk

The Company's foreign exchange management policy is to limit economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company's exposure to foreign exchange risk arises from future anticipated cash flows from its U.S. operations, debt service obligations on U.S. dollar borrowings, and from certain capital expenditure commitments denominated in U.S. dollars or other foreign currencies. The Company coordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally-occurring opposite movements and then dealing with any material residual foreign exchange risks; these are hereinafter referred to as being economically hedged. The Company may also use derivative instruments to manage foreign exchange risk.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

28. Risk management, continued:

Market risk, continued

Foreign exchange risk, continued

For the Company's facilities that have a U.S. functional currency, foreign exchange movements are largely matched within its U.S. operations and hence foreign exchange exposure is mitigated. At December 31, 2025, the Company held foreign exchange derivatives as disclosed in note 13.

At December 31, 2025, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would have decreased or increased net income attributable to shareholders by $39 million (2024 – decreased or increased by $12 million) and would have decreased or increased other comprehensive income by $nil (2024 – $1 million). This sensitivity analysis excludes the translation of subsidiaries that have a functional currency other than the Canadian dollar and financial instruments denominated in the functional currency in which they are transacted and measured. As a result, the impact to other comprehensive income reflects only the sensitivity relating to foreign exchange cash flow hedges at December 31, 2025.

Interest rate risk

The Company is exposed to changes in interest rates on its floating rate current and non-current loans and borrowings. At December 31, 2025, the proportion of fixed rate loans and borrowings was approximately 96% of total loans and borrowings outstanding (2024 – 94%). At December 31, 2025, the Company held interest rate derivatives to manage its remaining interest rate risk, as disclosed in note 13.

Credit risk

Credit risk is the risk of financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company. Credit risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into any agreements or transactions with the counterparty. Credit exposures, concentrations, and counterparty creditworthiness are subsequently monitored and are regularly reported to management on an ongoing basis.

Credit risk is managed and mitigated through a number of risk mitigation practices such as securing parent company guarantees, negotiating and obtaining security (such as cash deposits or letters of credit), and margining, when applicable.

Maximum credit risk exposure

The Company's maximum credit exposure was represented by the following financial assets:

At December 31,		**2025**		2024
Cash and cash equivalents (note 10)	**$**	**119**	$	865
Trade and other receivables (note 11)[1]		**569**		507
Derivative financial instruments assets (note 13)[1]		**688**		656
Finance lease receivable, non-current portion		**–**		13
Government grant receivable (note 14)		**320**		380
	$	**1,696**	$	2,421

1 The Company's maximum credit exposures related to trade and other receivables and derivative financial instruments assets by major credit concentration are comprised of maximum exposures of $1,029 million (2024 – $859 million) for wholesale counterparties and $228 million (2024 – $304 million) for generation and other counterparties.

At December 31, 2025, the Company held letters of credit of $95 million (2024 – $168 million) and parent company guarantees of $3,216 million (2024 – $3,693 million). At December 31, 2025 and 2024, the Company also held parent company guarantees which do not have a defined amount or limit, but which provide full support on any outstanding positions related to counterparty performance for power purchase arrangements and certain other operating and construction contracts.

Credit quality and concentrations

The Company is exposed to credit risk on outstanding trade and other receivables associated with its generation and optimization activities including PPAs, agreements with independent system operators, power sales contracts, energy supply agreements with government sponsored entities, wholesale customers, and trading counterparties. The Company is also exposed to credit risk related to its cash and cash equivalents (which include short-term investments), financial and non-financial derivative instruments assets and long-term financing arrangements.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

28. Risk management, continued:

Credit risk, continued

Credit quality and concentrations, continued

The credit quality and concentrations of the Company's trade and other receivables and other financial assets, by major credit concentrations are the following:

Cash and cash equivalents

The Company has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, are the primary counterparty of the Company's interest rate and foreign exchange derivative instruments, and facilitate letters of credit to mitigate the Company's exposure to certain counterparties. The Company manages its credit risk on cash and cash equivalents, and short-term investments by dealing with investment grade rated banks and financial institutions.

Generation credit risk

Credit risk exposure from PPAs, agreements with independent system operators, power sales contracts, and certain energy supply agreements is predominantly restricted to trade and other receivables and contract default. In certain cases, the Company relies on a single or small number of customers to purchase all or a significant portion of a facility's output.

The failure of any one of these counterparties to fulfill its contractual obligations could negatively impact the Company's financial results. Financial loss resulting from events of default by counterparties in certain PPAs may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Credit risk exposure is mitigated by dealing with creditworthy counterparties that are determined to be investment grade based on the Company's internally assigned ratings or employing mitigation strategies as noted above, netting amounts by legally enforceable set-off rights, and, when appropriate, taking security from the counterparty. Credit risk with counterparties in this asset class that are government-owned or sponsored entities and regulated public utility distributors is generally considered low.

Wholesale and merchant credit risk

Credit risk exposure for wholesale and merchant trading counterparties is measured by calculating the costs (or proceeds) of replacing the commodity position (physical and derivative contracts), adjusting for settlement amounts due to or due from the counterparty and, if permitted, netting amounts by legally enforceable set-off rights. Financial loss on wholesale contracts could include, but is not limited to, the cost of replacing the obligation, amounts owing from the counterparty or any loss incurred on liability settlements. Wholesale and merchant credit risk exposure is mitigated by trading with investment grade and creditworthy counterparties, portfolio diversification, monitoring of credit exposure limits, margining to reduce energy trading risks, obtaining parent company guarantees, and when appropriate, taking security from counterparties.

Trade and other receivables, financial derivative instruments and allowance for doubtful accounts

Trade and other receivables are substantially made up of receivables related to the generation and sale of electricity to customers including industrial and commercial customers, independent system operators from various regions and government-owned or sponsored entities and the settlement of financial derivative instruments related to merchant price risk mitigation and trading activities. Larger commercial and industrial customer contracts and contracts-for-differences provide for performance assurances including letters of credit if deemed appropriate. The Company manages its credit risk on these financial assets through its credit adjudication process, dealing with creditworthy counterparties and utilizing the credit risk mitigation practices noted above.

At December 31, 2025, the Company held $5 million (2024 – $5 million) in customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers. At December 31, 2025, the Company recorded an expected credit loss of $2 million (2024 – $2 million) on trade and other receivables associated with energy procurement counterparties.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's liquidity is managed by a centralized Treasury function. The Company manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and also by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are met through a combination of committed and demand revolving credit facilities, financings in public and private debt markets and equity offerings by the Company or its subsidiary CPLP. The Company also ladders its debt maturities to avoid large repayments in a single year.

At December 31, 2025, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $2,666 million (2024 – $1,836 million), of which $1,500 million is committed to 2030 (2024 – $1,000 million committed to 2029).

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

28. Risk management, continued:

Liquidity risk, continued

The Company has a shelf prospectus under which it may raise funds in the form of debt or equity, subject to market conditions. At December 31, 2025, Capital Power has a Canadian short-form base shelf prospectus, which expires in July 2026. Under the short-form base shelf prospectus, Capital Power may issue an unlimited number of common shares, preferred shares, and subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities, including up to $3 billion of medium-term notes by way of a prospectus supplement.

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities at December 31, 2025:

	Due within 1 year	Due between 1 and 2 years	Due between 2 and 3 years	Due between 3 and 4 years	Due between 4 and 5 years	After 5 years	Total
Non-derivative financial liabilities:							
Loans and borrowings[2] (note 19)	$ 526	$ 424	$ 1,329	$ 225	$ 279	$ 3,817	$ 6,600
Interest payments on loans and borrowings	331	319	281	229	218	676	2,054
Trade and other payables[3] (note 18)	719	–	–	–	–	–	719
Lease liabilities (note 20)	17	18	18	18	17	243	331
Derivative financial liabilities (net of financial assets):							
Commodity and other derivatives	58	108	96	69	55	199	585
Total	$ 1,651	$ 869	$ 1,724	$ 541	$ 569	$ 4,935	$ 10,289

2 Repayments of loans and borrowings excludes fair value differentials of $5 million related to debt assumed on previous asset acquisitions and $167 million related to repayments of tax equity financing through non-cash tax-equity attributes.

3 Excludes accrued interest on loans and borrowings of $70 million (note 18).

29. Capital management:

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay regular dividends to its shareholders, maintain a suitable credit rating, and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the growth strategy of the Company. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets.

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Company considers its capital structure to consist of loans and borrowings net of cash and cash equivalents and equity (which includes non-controlling interests).

The following table represents the total capital of the Company:

At December 31,	2025	2024
Loans and borrowings (note 19)	$ 6,730	$ 4,976
Lease liabilities[1] (note 20)	162	151
Cash and cash equivalents (note 10)	(119)	(865)
Net debt	6,773	4,262
Share capital (note 23)	5,036	4,301
Deficit and other reserves	(179)	275
Non-controlling interests	(8)	(5)
Total equity	4,849	4,571
Total capital	$ 11,622	$ 8,833

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

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

29. Capital management, continued:

Capital Power has been assigned the following ratings on its Senior Unsecured Debt; a BBB- (stable outlook) Corporate Credit Rating by Standard & Poor's (S&P), BBB (low) Issuer Rating with a stable trend by DBRS Limited (DBRS), and BBB- (stable outlook) Long-term Issuer Default Rating by Fitch Ratings. Capital Power has preferred share ratings of P-3 (stable outlook) assigned by S&P and Pfd-3 (low) with a stable trend assigned by DBRS.

Capital Power has the following externally imposed requirements on its capital as a result of its credit facilities and certain debt covenants, as defined in the respective agreements:

- Maintenance of modified consolidated total assets to consolidated total assets ratio, as defined in the debt agreements, of not less than 0.75 to 1.0;
- Maintenance of consolidated senior debt to consolidated capitalization ratio, as defined in the debt agreements, of not more than 0.65 to 1.0;
- Limitation on debt issued by subsidiaries; and
- In the event that Capital Power is no longer Investment Grade – meaning it has been assigned at least two separate ratings from the following agencies that are lower than "BBB-" from S&P, "BBB (low)" from DBRS, and "BBB-" from Fitch – Capital Power would also be required to maintain a ratio of consolidated earnings before interest, income taxes, depreciation and amortization to consolidated interest expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

For the years ended December 31, 2025 and 2024, Capital Power complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Company can issue new loans and borrowings, issue common or preferred shares, buy back common shares, redeem preferred shares, repay existing loans and borrowings or adjust dividends paid to its shareholders.

30. Interests in joint arrangements and associates:

Joint operations

The Company holds interests in the following joint operations at December 31, 2025:

	Place of business	% of ownership interest
Joffre Cogeneration Project (Joffre)[1]	Canada	40%
Shepard Energy Centre (Shepard)[2]	Canada	50%
Frederickson 1 Generating Station[3]	United States	50.15%

1 Joffre is a 480 MW gas-fired combined cycle cogeneration facility with external parties holding 40% and 20% interests, respectively.
2 Shepard is an 881 MW gas-fired generating facility, the other 50% is held by an external party.
3 Frederickson 1 is a 265 MW natural gas-fired combined-cycle generating facility, the other 49.85% is held by an external party.

There are no significant restrictions pertaining to the joint operations described above.

Equity-accounted investments

Joint ventures

The Company holds interests in the following joint ventures at December 31, 2025:

	Place of business	% of ownership interest
York Energy Centre L.P.[4]	Canada	50%
MCV Partners LLC[5]	United States	50%
New Harquahala Generating Company, LLC[6]	United States	50%
CP (Quality Wind) Limited Partnership[7]	Canada	51%
Capital Power (PDN) L.P.[7]	Canada	51%

4 York Energy Centre L.P. (York Energy) is a 494 MW natural gas-fired power generating facility, located in Ontario, Canada, the other 50% is held by an external party.
5 Midland Cogeneration Venture LP (Midland Cogen) is a 1,633 MW natural gas combined cycle cogeneration facility located in Michigan, USA. The other 50% is held by an external party. MCV Partners LLC (MCV) owns 100% of MCV Holding Company LLC which owns 100% of Midland Cogen.
6 New Harquahala Generating Company, LLC (New Harquahala) is a 1,092 MW natural gas-fired combined cycle generation facility, located in Maricopa County, Arizona. The other 50% is owned by BlackRock. Capital Power operates, maintains, and manages the facility for an annual management fee.
7 On December 20, 2024, Axium, through one of its managed funds, acquired a 49% interest in Capital Power's Port Dover and Nanticoke Wind and Quality Wind facilities. Total pre-tax cash proceeds to Capital Power from the transaction were $333 million, inclusive of working capital. Axium and Capital Power formed two new partnerships which reflect their respective 49% and 51% ownership interests. While Capital Power continues to manage and operate the two wind facilities on behalf of the newly formed partnerships pursuant to long-term asset management agreements, Capital Power jointly controls the assets with Axium under the new partnership. Accordingly, the December 20, 2024 transaction resulted in a loss of control of the Port Dover and Nanticoke Wind and Quality Wind facilities subsidiary companies whereby Capital Power no longer fully consolidates the wind facilities and uses the equity method in its financial statements. For the year ended December 31, 2024, a total gain of $309 million was recorded on this transaction in the consolidated statement of income. This gain includes $151 million related to the 49% interest sold to Axium and $158 million upon remeasurement of Capital Power's remaining 51% interest to its fair value when control was lost. Total assets and liabilities with a carrying amount of $355 million were derecognized, and no amounts were recognized to other comprehensive income. CP (Quality Wind) Limited Partnership (Quality Wind) is a 142 MW wind generation facility, located in British Columbia and Capital Power (PDN) L.P. (PDN Wind) is a 105 MW wind generation facility, located in Ontario.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

30. Interests in joint arrangements and associates, continued:

Equity-accounted investments, continued

Joint ventures, continued

Summarized financial information of the Company's joint ventures:

	York Energy		MCV		New Harquahala		PDN Wind		Quality Wind		Total	Total
Statements of Financial Position	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Cash and cash equivalents	**$ 21**	$ 41	**$ 39**	$ 86	**$ 58**	$ 24	**$ 9**	$ 4	**$ 11**	$ –	**$ 138**	$ 155
Other assets – current	**14**	8	**97**	91	**25**	28	**13**	4	**17**	12	**166**	143
Non-current assets	**232**	217	**1,013**	1,123	**857**	1,002	**136**	137	**222**	226	**2,460**	2,705
Other financial liabilities – current	**(6)**	–	**(67)**	(104)	**(34)**	(9)	**(1)**	(1)	**–**	–	**(108)**	(114)
Trade and other payables	**(12)**	(7)	**(63)**	(48)	**(17)**	(21)	**–**	(2)	**–**	(5)	**(92)**	(83)
Financial liabilities – non-current	**(306)**	(312)	**(340)**	(424)	**(390)**	(435)	**(5)**	(6)	**–**	–	**(1,041)**	(1,177)
Other liabilities – non-current	**(1)**	(2)	**(5)**	(4)	**(25)**	(25)	**(19)**	(5)	**(24)**	(9)	**(74)**	(45)
Net assets	**$ (58)**	$ (55)	**$ 674**	$ 720	**$ 474**	$ 564	**$ 133**	$ 131	**$ 226**	$ 224	**$ 1,449**	$ 1,584

	York Energy		MCV		New Harquahala		PDN Wind		Quality Wind		Total	Total
Statements of Income and Comprehensive Income	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Revenues	**$ 85**	$ 73	**$ 704**	$ 624	**$ 200**	$ 181	**$ 44**	$ –	**$ 56**	$ –	**$ 1,089**	$ 878
Energy purchases and fuel	**(19)**	(11)	**(443)**	(301)	**(1)**	(1)	**–**	–	**–**	–	**(463)**	(313)
Other raw materials and operating charges	**(5)**	(5)	**(36)**	(35)	**(27)**	(39)	**(6)**	–	**(7)**	–	**(81)**	(79)
Staff costs and employee benefits expense	**–**	–	**(17)**	(15)	**(10)**	–	**–**	–	**–**	–	**(27)**	(15)
Other administrative expense	**(3)**	(4)	**(35)**	(43)	**(17)**	(25)	**(2)**	–	**(5)**	–	**(62)**	(72)
Depreciation and amortization	**(9)**	(7)	**(116)**	(100)	**(52)**	(46)	**(15)**	–	**(18)**	–	**(210)**	(153)
Gains on disposals and other transactions	**(1)**	1	**–**	–	**–**	–	**–**	–	**–**	–	**(1)**	1
Net finance expense	**(15)**	(14)	**(23)**	(29)	**(33)**	(30)	**–**	–	**–**	–	**(71)**	(73)
Net income (loss)	**33**	33	**34**	101	**60**	40	**21**	–	**26**	–	**174**	174
Other comprehensive income that will not be reclassified to net income	**–**	–	**–**	(2)	**–**	–	**–**	–	**–**	–	**–**	(2)
Other comprehensive income that may be reclassified to net income	**–**	–	**(13)**	(1)	**(10)**	6	**–**	–	**–**	–	**(23)**	5
Total comprehensive income	**$ 33**	$ 33	**$ 21**	$ 98	**$ 50**	$ 46	**$ 21**	$ –	**$ 26**	$ –	**$ 151**	$ 177

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

30. Interests in joint arrangements and associates, continued:

Equity-accounted investments, continued

Joint ventures, continued

A reconciliation of the Company's recorded equity investment in each joint venture is as follows:

	York Energy		MCV		New Harquahala		PDN Wind		Quality Wind		Total[1]	Total[1]
	2025	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
At January 1	**$ 58**	$ 129	**$ 358**	$ 296	**$ 337**	$ –	**$ 149**	$ –	**$ 190**	$ –	**$ 1,092**	$ 425
Acquisition	**–**	–	**–**	–	**–**	316	**–**	149	**–**	190	**–**	655
Share of net income	**17**	16	**16**	51	**30**	20	**11**	–	**14**	–	**88**	87
Distributions received	**(18)**	(76)	**(17)**	(20)	**(18)**	(24)	**(5)**	–	**(8)**	–	**(66)**	(120)
Other comprehensive income (loss)	**–**	–	**(5)**	3	**(6)**	3	**–**	–	**–**	–	**(11)**	6
Amortization of fair value of net assets acquired	**(11)**	(11)	**–**	–	**–**	–	**–**	–	**–**	–	**(11)**	(11)
Foreign exchange gain (loss)	**–**	–	**(17)**	28	**(15)**	22	**–**	–	**–**	–	**(32)**	50
At December 31,	**$ 46**	$ 58	**$ 335**	$ 358	**$ 328**	$ 337	**$ 155**	$ 149	**$ 196**	$ 190	**$ 1,060**	$ 1,092

1 At December 31, 2025, the Company's equity-investment in its associate C2CNT is $4 million (US$3 million) (2024 – $4 million (US$3 million)).

In 2024, management made the strategic decision to redirect resources from the Company's C2CNT equity-accounted investment to better serve our customers with balanced energy solutions. The C2CNT equity-accounted investment was tested for impairment and the fair values of the underlying assets were determined using a depreciated replacement cost valuation approach, which was the primary estimate underlying the assessment of the investment's recoverable amount. The carrying amount of the Company's C2CNT equity-accounted investment of $30 million (US$23 million) was above its estimated recoverable amount and an impairment of $27 million (US$20 million) was recorded.

Each of the Company's joint ventures is party to long-term transportation contracts and operating and maintenance contracts. The Company's share of each joint venture's approximate future payments on the contracts are as follows:

	York Energy	MCV	New Harquahala	PDN Wind	Quality Wind	Total
Within one year	**$ 4**	**$ 70**	**$ 17**	**$ 5**	**$ 5**	**$ 101**
Between one and five years	**16**	**145**	**78**	**21**	**22**	**282**
After five years	**25**	**4**	**167**	**17**	**12**	**225**
	$ 45	**$ 219**	**$ 262**	**$ 43**	**$ 39**	**$ 608**

31. Commitments, contingencies, and guarantees:

Projects

The Company is committed to the following projects at December 31, 2025:

	Contracted Capacity	Capital cost commitment	Expected completion date	Location
Growth Projects:				
Repowering of Genesee 1 and 2	512 MW	$10-96	Achieved commercial operations Q4 2024 and the project is substantially complete	Alberta
Ontario growth projects	276 MW	$61	York and Goreway BESS completed Q3 2025 East Windsor Expansion Q3 2026	Ontario
Maple Leaf Solar	73 MW	$158	Q1 2027	North Carolina
Bear Branch Solar	35 MW	$55	Q4 2026	North Carolina
Hornet Solar	73 MW	$54	Q3 2026	North Carolina
Commercial Initiatives:				
Arlington Valley capacity uprate (note 15)	35 MW	$52	2026/2027	Arizona

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

31. Commitments, contingencies, and guarantees, continued:

Long-term contracts

The Company is party to a number of long-term energy purchase and transportation contracts, operating and maintenance contracts and contracts to purchase environmental credits. Some of the energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated statement of financial position as derivative financial instruments assets and liabilities as appropriate. Approximate future payments under each group of contracts are as follows:

	Energy purchase and transportation contracts[1]	Operating and maintenance contracts	Environmental credits[2]
Within one year	$ 385	$ 142	$ 156
Between one and five years	837	529	80
After five years	714	597	30
	$ 1,936	$ 1,268	$ 266

1 Based on gross settlement amounts.
2 Future environmental credit purchases are presented net of future environmental credit sales.

Line Loss Rule Proceeding

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

As a result of the LLR Proceeding, Capital Power incurred additional charges related to historical periods. Net expenses of $19 million were recorded in prior years to reflect the Company's net obligation. The invoicing process resulted in gross billings to Capital Power of which those amounts not attributable to Capital Power were largely recovered from the appropriate parties, with the exception of those related to the Sundance C PPA from the Balancing Pool.

The Balancing Pool is disputing its liability to make payment for the LLR adjustment invoices related to the Sundance C PPA, which amounts to a net potential exposure to Capital Power of approximately $25 million recorded within other assets at December 31, 2025. The Company believes the various agreements governing the termination and transfer of the Sundance C PPA and related transmission agreements with the AESO had the effect of transferring all past liabilities for the Sundance C PPA to the Balancing Pool. Capital Power therefore filed a statement of claim at the Alberta Court of Queen's Bench on January 11, 2021 against the Balancing Pool, the Province of Alberta and the AESO in which it is sought, among other relief, recovery from the Balancing Pool and the Province of Alberta of all amounts Capital Power was compelled to pay to the AESO on account of the LLR adjustment invoices relating to the Sundance C PPA as well as interest and legal costs, including the portion invoiced to the Balancing Pool but not received by the Company pertaining to all tranches of invoices. Capital Power has since discontinued its claim against the AESO but continues to proceed against the Balancing Pool and the Province of Alberta. This process remains ongoing. Capital Power expects to ultimately realize the full amount of the gross receivables related to the line losses upon resolution of the dispute.

Legal claim

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

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.

Guarantees

The Company, through its subsidiary CPLP, has issued letters of credit of $604 million (2024 – $608 million) to meet the credit requirements of energy market participants, conditions of certain service agreements, and to satisfy reclamation requirements.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

32. Segment information:

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

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

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

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

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

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

32. Segment information, continued:

	Year ended December 31, 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	$ 2,128	$ 33	$ 1,904	$ 161	$ 40	$ 4,266	$ (546)	$ –	$ 3,720
Energy purchases and fuel	(1,287)	(8)	(1,043)	5	–	(2,333)	232	–	(2,101)
Other raw materials and operating charges	(88)	(24)	(128)	(19)	(6)	(265)	41	–	(224)
Staff costs and employee benefits expense	(48)	(3)	(36)	(3)	(109)	(199)	16	–	(183)
Other administrative expense	(60)	(17)	(63)	(20)	(116)	(276)	30	–	(246)
Remove unrealized changes in fair value of commodity derivatives	92	130	141	(21)	–	342	–	(342)	–
Remove other non-recurring items[2]	4	–	–	–	41	45	–	(45)	–
Adjusted EBITDA[3]	741	111	775	103	(150)	1,580			
Depreciation and amortization									(580)
Foreign exchange gain									21
Loss on disposals and other transactions									(10)
Net finance expense									(307)
Income from equity-accounted investments									77
Income before tax									$ 167

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

32. Segment information, continued:

	Year ended December 31, 2024								
	Canada flexible generation[1]	Canada renewables[1]	U.S. flexible generation[1]	U.S. renewables	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	Consolidated IFRS financials
Revenues and other income	$ 2,350	$ 353	$ 1,363	$ 130	$ 19	$ 4,215	$ (439)	$ –	$ 3,776
Energy purchases and fuel	(1,357)	(13)	(575)	1	1	(1,943)	156	–	(1,787)
Other raw materials and operating charges	(90)	(28)	(105)	(19)	(6)	(248)	39	–	(209)
Staff costs and employee benefits expense	(56)	(2)	(27)	(1)	(177)	(263)	9	–	(254)
Other administrative expense	(59)	(21)	(53)	(22)	(82)	(237)	36	–	(201)
Remove unrealized changes in fair value of commodity derivatives	(67)	(135)	(49)	13	–	(238)	–	238	–
Remove other non-recurring items	8	–	–	–	49	57	–	(57)	–
Adjusted EBITDA[3]	729	154	554	102	(196)	1,343			
Depreciation and amortization									(503)
Impairments									(27)
Foreign exchange loss									(29)
Gain on divestiture									309
Loss on disposals and other transactions									(31)
Net finance expense									(221)
Income from equity-accounted investments									76
Income before tax									$ 899

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

2 Includes acquisition and integration costs of $41 million for the acquisition of Hummel Station, LLC and Rolling Hills Generating, LLC (note 4).

3 Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Additional geographic information

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

Select non-current assets within each geographic area are:

	At December 31, 2025			At December 31, 2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Property, plant and equipment	**$ 5,592**	**$ 5,661**	**$ 11,253**	$ 5,457	$ 2,604	$ 8,061
Equity-accounted investments (note 30)	**397**	**667**	**1,064**	397	699	1,096
Intangible assets and goodwill	**428**	**192**	**620**	519	225	744
Right-of-use assets	**50**	**86**	**136**	54	64	118
Other assets[4]	**59**	**61**	**120**	73	84	157
	$ 6,526	**$ 6,667**	**$ 13,193**	$ 6,500	$ 3,676	$ 10,176

4 Includes current portion of finance lease receivable.

Notes to the consolidated financial statements

December 31, 2025 and 2024
(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

32. Segment information, continued:

Major customers

For the year ended December 31, 2025, the Company recorded revenues of $613 million from the Alberta Electric System Operator, within the Canada flexible generation and Canada renewables segments (year ended December 31, 2024 – $780 million), and $483 million from PJM (2024 - nil), within the U.S. flexible generation segment. 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:

	Year ended December 31, 2025						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,764	$ 76	$ 964	$ 64	$ 2,868	$ 701	$ 3,569
Emission credit revenues	–	48	–	3	51	(5)	46
Total revenues[5]	$ 1,764	$ 124	$ 964	$ 67	$ 2,919	$ 696	$ 3,615

	Year ended December 31, 2024						
	Canada flexible generation	Canada renewables	U.S. flexible generation	U.S. renewables	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,845	$ 157	$ 441	$ 48	$ 2,491	$ 1,044	$ 3,535
Emission credit revenues	–	44	–	3	47	95	142
Total revenues[5]	$ 1,845	$ 201	$ 441	$ 51	$ 2,538	$ 1,139	$ 3,677

5 Included within trade and other receivables at December 31, 2025, were amounts related to contracts with customers of $321 million (2024 – $255 million).

33. Comparative figures:

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

Appendix

TCFD alignment table

Task Force on Climate-Related Financial Disclosures (TCFD)

This section reviews our strategy and its resiliency in relation to climate-related risks and opportunities, and is structured in accordance with the recommendations of the Task Force on Climate-Related Financial Disclosures (TCFD).

TCFD theme	Topic and recommended content	Reference
Governance	Describe Board's oversight of climate-related opportunities and risks	▸ 2026 Management Proxy Circular, Sustainability and climate oversight
	Describe management roles in assessing and managing climate-related opportunities and risk	▸ 2025 Corporate governance ▸ 2026 Management Proxy Circular, Sustainability and climate oversight ▸ Who we are > Corporate governance (www.capitalpower.com)
Strategy	Describe climate-related risks identified over the short, medium, and long-term	▸ TCFD Risks and opportunities tables ▸ 2025 Integrated Annual Report, Executing our strategic focus and Governance and risk management
	Describe impact of climate-related opportunities and risks on the business strategy and financial planning	▸ TCFD Risks and opportunities tables
	Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario.	▸ TCFD Scenario analysis
Risk management	Describe processes for identifying and assessing climate-related risks	▸ 2025 Integrated Annual Report, Our approach to risk management ▸ 2025 Integrated Annual Report, Risks and risk management, Climate change, Business report ▸ TCFD Risks and opportunities tables
	Describe processes for managing climate-related risks	▸ 2025 Integrated Annual Report, Our approach to risk management ▸ 2025 Integrated Annual Report, Risks and risk management, Climate change, Business report ▸ TCFD Risks and opportunities tables
	Describe how processes for identifying, assessing, and managing climate-related risks are integrated into the overall risk management process	▸ 2025 Integrated Annual Report, Our approach to risk management ▸ 2025 Integrated Annual Report, Risks and risk management, Climate change, Business report
Targets and metrics	Disclose metrics used to assess climate-related opportunities and risks aligned with the strategy and risk management process	▸ 2025 Integrated Annual Report, 2026 performance targets ▸ 2025 Integrated Annual Report, Emissions management
	Disclose Scope 1, 2, and 3 GHG emissions and related risks	▸ 2025 Integrated Annual Report, Emissions management
	Describe targets used by the Company to manage climate-related opportunities and risks, and performance against targets	▸ 2025 Integrated Annual Report, 2026 performance targets ▸ 2025 Integrated Annual Report, Executing our strategic focus

Scenarios analysis

Capital Power's strategy is established through rigorous review of the Company's competitive advantages, as well as market fundamentals, changing public policies and evolving long-term dynamics that are shaping the power sector. Through regular assessments, we test and review our strategy to ensure resiliency. This process includes Board oversight and extensive management review to ensure Capital Power's strategy is adjusted as the competitive environments in which we operate continue to change.

To support this process, Capital Power considers opportunities and risks under varying climate-related conditions to help understand the resiliency of our strategy. The International Energy Agency (IEA) scenarios and their underlying assumptions are among the resources we consider when evaluating these potential risks and opportunities. These scenarios present possible climate-related pathways and help inform our strategy in the jurisdictions where we operate. As we evaluate these potential risks and opportunities, we focus on those that are most material to our business.

TCFD alignment table

IEA scenarios

The IEA scenarios make assumptions about technology advancement, policy, CO_2 prices, fuel prices, socio-economic drivers, including population and GDP, and considers global trends toward increasing net zero commitments by governments and corporations. The IEA scenarios simulate the interactions among supply and demand fundamentals and output the resulting energy flows, CO_2 emissions and investments to 2050.

Note: The IEA's 2025 World Energy Outlook Report provides a framework for thinking about the future of global energy. It does not make predictions about the future. Instead, it sets out what the future could look like based on different scenarios or pathways, with the aim of providing insights to inform decision making by governments, companies and others concerned with energy.

The following includes a summary of each of the three main scenarios from the 2025 IEA report used in Capital Power's analysis:

- **Stated Policies Scenario** (STEPS) assumes that existing and announced policy is implemented by governments. The cumulative contributions that result are material, however not sufficient to achieve the sustainable development goals or limit the worst effects of climate change.
- **Current Policies Scenario** (CPS) reflects energy and climate measures that are formally enacted in existing legislation and regulation, without assuming implementation of any announced or future policy changes.
- **Net Zero Emissions by 2050 case** (NZE) sets out the pathway for the global energy sector to achieve the ambition of net zero CO_2 emissions by 2050.

Overview of 2025 IEA scenarios and the resiliency of our strategy

The 2025 IEA scenarios provide the critical steps required for understanding the pathways toward a lower-carbon future and the implications for global energy systems. Capital Power supports the insights these scenarios offer and incorporates them into our strategic planning to ensure resiliency under a range of potential outcomes.

Our strategy is designed to remain adaptable as market conditions, technologies, and policies evolve. We recognize the importance of advancing solutions that can reduce emissions and enhance reliability, and we actively evaluate opportunities that align with the direction outlined in the IEA scenarios. This includes exploring innovative technologies and approaches that can improve performance and support the transition to a more sustainable energy system.

As global electricity demand grows, a balanced mix of energy sources will be critical to meeting reliability and affordability needs. Capital Power's renewable development is expected to remain strong across all scenarios, while our thermal generation will evolve over time to reflect changing expectations and opportunities. By integrating scenario analysis into our planning, we aim to position our business to succeed in a dynamic environment and contribute to a resilient, lower-carbon future.

Risk and opportunities tables

Transitional risks and opportunities

Transition risks and opportunities to our business include risks associated with regulatory and government policy change, technology developments, changing market demands and reputational risks.

The tables below identify short- and long-term transitional risks that may materialize in scenarios where increasing measures are taken to mitigate the impacts of climate change. Similarly, transitional opportunities that may arise in these scenarios are evaluated over the short- and long-term.

Markets, policy, and regulatory

Key assumptions		▸ Carbon pricing remains a central mechanism of climate policy in Canada and the US, with the pace and scope of escalation varying by jurisdiction. ▸ Stimulus spending by governments is increasingly focused on energy and low-carbon infrastructure. ▸ Demand growth accelerates globally due to electrification and economic development. ▸ Carbon markets continue to expand across North America.
Risks	**Short-term**	▸ Changes in governments create policy uncertainty. ▸ Increased carbon pricing exposure due to modifications in existing policy and/or thermal asset additions to the Capital Power fleet.
	Long-term	▸ Continued decarbonization pressure of the power sector in Canada and the United States. ▸ Enhanced adoption and escalation in carbon prices and more stringent benchmarks continue in response to pressure to reduce emissions through market mechanisms.
Mitigation		▸ Unmitigated thermal assets are increasingly expensive to operate. We pursue commercially viable low-carbon solutions to minimize exposure to carbon pricing. ▸ Actively manage compliance costs through participation in carbon markets, investments to improve operational efficiencies that reduce emissions. ▸ Carbon costs are passed through to counterparties on select power purchase agreements, minimizing exposure to carbon price. ▸ Costs and risks associated with emissions abatement from thermal assets are considered in commercial decision making and due diligence. ▸ Active participation in industry groups to monitor and engage with government officials on emerging policy development relating to climate change and carbon pricing. ▸ Analysis relating to carbon prices and regulation is embedded in commercial decisions and due diligence.
Opportunities	**Short-term**	▸ Rising carbon prices may lead to increases in the wholesale price of power where generators are able to flow-through costs to consumers. ▸ Expansion of carbon markets continues across North America.
	Long-term	▸ Demand growth accelerates as industries are increasingly using electrification as a means to reduce emissions. ▸ Emission-intensive assets with limited opportunities for abatement retire as rising carbon costs limit the economic viability of the assets.
Response		▸ Expertise in carbon markets leads to reduced compliance costs through hedging and origination. ▸ Increase trading activity in environmental markets. ▸ Rising demand for power and the retirement of emission-intensive assets results in an increase in investment opportunities for Capital Power.

Risk and opportunities tables

Renewable energy development

Key assumptions		▸ Investment in renewables continues as part of broader efforts to decarbonize electricity grids. ▸ The cost of renewable technologies continues to decline; capacity values of renewables increase with technological improvements, expanded regional diversity and co-location with storage assets. ▸ Penetration of renewables continues to increase as demand grows and retirement of existing assets continues. ▸ Intermittency remains a concern for grid reliability; natural gas and storage are essential to integration in the long-term. ▸ New transmission development is required to expand the capacity of renewable generation.
Risks	**Short-term**	▸ Increasing penetration of intermittent renewable energy affects the profile of supply fundamentals. ▸ Policies and regulations related to renewable energy and emissions will continue to evolve, potentially affecting market conditions. This includes reduction in tax incentives and grants in both Canada and the U.S. ▸ Policy uncertainty or slower rollout of incentives under CPS may affect near-term economics of renewable projects.
	Long-term	▸ Long-term declines in the cost of renewables, as well as reduced intermittency through the addition of storage, improves the relative competitiveness of these assets and results in increased development. Capital Power's existing fleet of thermal assets may be affected by this increased penetration.
Mitigation		▸ Capital Power operates a diverse fleet of assets that includes baseload and peaking units well-suited to varying market conditions. ▸ Capital Power invests strategically in assets that are expected to remain competitive with increasing levels of renewable penetration.
Opportunities	**Short-term**	▸ There are expanded opportunities in renewables across North America as cost declines and policy supports new development. ▸ Intermittent renewable generation increases the volatility of power prices and creates a need for flexible capacity to support integration.
	Long-term	▸ Long-term declines in the costs of renewables increase the relative competitiveness of these assets and result in increased development.
Response		▸ Assess development opportunities in renewables, including wind, solar and storage. ▸ Operate flexible natural gas assets that provide critical reliability services to the grid. ▸ Well-positioned to pursue development opportunities for new renewable assets.

Risk and opportunities tables

Natural gas competitiveness and decarbonization

Key assumptions		▸ Natural gas remains an important component of the supply mix long-term for reliability and renewable integration. ▸ Regulation of carbon emissions is gradually increased to limit emissions from thermal assets. ▸ Decarbonization of the fuel mix is expanded through policy and funding that supports innovation and deployment. ▸ Operating profiles of thermal assets change as they increasingly are used to meet the net demand from intermittent renewables; flexible assets in strategic locations remain competitive.
Risks	**Short-term**	▸ Policy and regulation directed at reducing carbon emissions from thermal assets may reduce margins on certain assets.
	Long-term	▸ Competitiveness of renewables and other low-emission sources of electricity may reduce market share for natural gas generation. ▸ Potential for policy constraints on natural gas use over time which could affect competitiveness and capital allocation decisions. Regulation of this nature would affect Capital Power's strategy, financial position and capital allocation decisions.
Mitigation		▸ Investment in critical natural gas assets that provide grid reliability and support renewable integration. These assets are expected to remain competitive under increasingly stringent carbon regulations and are at reduced risk due to their shorter operating life relative to new gas assets. ▸ Economic assessment of development of new gas assets assumes shorter asset lives to account for long-term uncertainty. ▸ Active engagement which includes lobbying with policymakers and industry associations to ensure there is a long-term role for higher efficiency and lower emitting natural gas generation in the supply mix to support renewable integration, maintain reliability and service the expected demand growth. ▸ Decarbonization through commercially viable low-carbon solutions. ▸ Advocacy to ensure policy support and wide-scale adoption of technologies that support decarbonization.
Opportunities	**Short-term**	▸ Policy and regulation directed at carbon emissions from thermal assets affect supply fundamentals and, in certain jurisdictions, may increase the wholesale price of power. ▸ Increasing penetration of intermittent sources of energy increases the need for flexible assets. ▸ Contracting flexible generation assets for data centre co-location.
	Long-term	▸ Uncertainty over long-term opportunities in natural gas assets limits competition for acquisitions.
Response		▸ Investment in operational efficiencies and enhancements that improve emissions performance allow assets to realize increased margins through reduced compliance costs and improved competitiveness. ▸ Capital Power allocates capital to critical natural gas assets situated at strategic locations. These assets have potential to realize increased margins as flexibility services are in higher demand. ▸ Capital Power pursues acquisitions of critical natural gas assets to support reliability and integration of renewables. ▸ Exploring emerging technologies that may support decarbonization such as SMR and post combustion CCS technologies. ▸ In jurisdictions where competitiveness of natural gas is significantly reduced, shift capital allocation to alternative assets including renewables. Capital Power's asset allocation plans are informed by expected market fundamentals and would be adjusted accordingly.

Risk and opportunities tables

Disruptive technology and energy transition

Key assumptions		▸ Evolving customer demands, including preferences for reliable, affordable and cleaner power will drive innovation and transformation of the power sector. ▸ Awareness and concern among end-use consumers of their contribution to climate change will influence behavioural changes in energy consumption. ▸ Decarbonization, decentralization and digitalization will drive transformation of energy production and consumption. ▸ Use of technologies for emissions abatement is increasingly deployed across the power sector over the long-term with increasing carbon prices.
Risks	**Short-term**	▸ Decentralized sources of non-emitting energy, including demand response, reduce overall demand, which could impact wholesale prices. ▸ Changes to government policies and political landscapes could affect the speed at which technologies can be developed and implemented.
	Long-term	▸ Innovation, development and improved competitiveness of non-emitting technologies that fall outside of Capital Power's current core competencies may affect strategy and capital allocation. New sources of competition for dispatchable natural gas emerge from non-emitting resources and demand response; this may reduce competitiveness of natural gas generation.
Mitigation		▸ Actively monitor policy and market fundamentals that may drive investment in disruptive technologies that could affect asset competitiveness and financials. ▸ Due diligence assessments identify site-specific impacts that may arise from trends in decentralization and decarbonization. ▸ Monitor emerging technologies and evaluate their potential economic impact with scenario analysis. ▸ Actively monitor emission abatement technologies and assess opportunities to expand our portfolio of technologies that may have direct application in reducing emissions in natural gas generating assets. ▸ Early renew existing PPAs and sign long-term PPAs with existing assets that have merchant exposure.
Opportunities	**Short-term**	▸ Commercial-scale deployment of emissions abatement technology is supported through policy and regulation and public funding is available to encourage customer uptake of new technology. ▸ Policy support for early-stage development of emission abatement technology encourages the pursuit of new innovations. This could include the acquisition of new assets or companies with innovative technology.
	Long-term	▸ Technological advancement and digitalization allow greater control of energy generation and consumption by demand-side market participants. ▸ Emission abatement technologies that support long-term viability of natural gas proliferate and expand development opportunities.
Response		▸ Actively pursue technologies that are assessed to be commercially deployable at scale in the power sector to reduce emissions from operations. ▸ Seek funding for projects to assess promising emerging technologies that can reduce emissions in line with the Company's strategy. ▸ Establish partnerships to advance innovations and early-stage emissions abatement technologies. ▸ Consider pursuing partnerships with companies that are pursuing technologies that have high likelihood of commercial deployment in electricity generation for emissions abatement.

Risk and opportunities tables

Reputational

Key assumptions		▸ Climate change-related impacts have the potential to create material reputational risks. We actively manage our exposure and transparently report on the risks and mitigation strategies.
Risks	**Short-term**	▸ Investors are increasingly averse to investments that exhibit higher risks resulting from exposure to climate change. ▸ Stakeholders are increasingly focused on exposure to the impacts of climate change, and risks related to our portfolio, which includes carbon emitting assets. ▸ Attracting and retaining employees becomes challenging as preferences for employment favour companies with reduced exposure to climate change and fewer or no carbon-intensive assets. ▸ Counterparties and off-takers favour generators with lower exposure to climate change.
	Long-term	▸ Increasing frequency and severity of climate change-related events may affect company assets and create reputational, investor risk and third-party liability risk. ▸ Cost of capital could increase due to changing investor sentiment in relation to climate-related financing.
Mitigation		▸ An existing sustainability linked loan ties our environmental performance to our financing activities to demonstrate our commitment in achieving our corporate objectives. ▸ Coal-fired generation is phased out along withour investment in repowering at the Genesee facility. ▸ ESG criteria is integrated into our investment decisions to ensure appropriate consideration of climate change-related risks. ▸ Commitment to transparent reporting and disclosure to help address concerns and risks among investors and stakeholders. ▸ Dedicated subject matter expertise is retained in areas related to disaster management, risk management, regulatory compliance and community engagement to proactively manage the impacts of climate change-related events on physical assets, financial position and reputation. ▸ Capital allocation plans where long-term reputational risks arising from climate change cannot be mitigated with decarbonization strategies. Our portfolio of assets would be rebalanced accordingly as fundamentals evolve.
Opportunities	**Short-term**	▸ Climate change-related impacts that affect operations may also negatively affect Capital Power's reputation as a reliable power generator in the communities where we operate. ▸ Transparent reporting and credible strategies to improve environmental performance help build trust with investors and stakeholders.
	Long-term	▸ Companies that actively manage their exposure to climate change-related risks are expected to outperform those that do not adequately address the risks. ▸ Achieving ambitious reductions in emissions through aggressive pursuit of decarbonization strategies helps to ensure long-term sustainability.
Response		▸ Leadership in responsible construction, operation and maintenance of power generating facilities that ensures resiliency from increasing climate change-related risks that could negatively affect the Company's reputation. ▸ Transparent communication and reporting of progress toward the deployment of decarbonization strategies.

Risk and opportunities tables

Physical risks and opportunities

The following tables assess physical risks and opportunities that may be realized in scenarios where the impacts of climate change are increasingly observed in the power sector.

Acute

Key assumptions		▸ Climate change will cause an increase in extreme weather affecting Capital Power's current and future assets and extreme weather events will become increasingly frequent and severe.
Risks	**Short-term**	▸ Extreme weather events caused by climate change could have an impact on our operations and critical infrastructure and trigger increased insurance costs (higher deductibles and increased premiums) and potential liabilities.
	Long-term	▸ A persistent and material increase over time in the frequency and severity of extreme weather events caused by climate change may affect insurance costs and the ability to secure coverage on specific high-risk assets. ▸ Outright exclusion of severe weather-related perils by insurers.
Mitigation		▸ Increases in extreme weather are included in our risk assessment process. ▸ Monitor the insurance market for material changes to policies that may affect our ability to seek coverage for high-risk assets. ▸ Emergency Preparedness and Response plans are in place for our facilities, with responses tested through simulated disasters in tabletop exercises. Continuous improvement processes ensure learnings are incorporated in future responses. ▸ Sustaining capital is directed to enhancements that mitigate risk. ▸ Capital Power assesses climate change-related physical risk in the due-diligence process for new acquisitions.
Opportunities	**Short-term**	▸ Increasing frequency and severity of acute climate impacts may affect delivery of energy through wire infrastructure from assets situated on remote parts of the transmission system and that are at risk due to single points of failure, increasing the value of our strategically located assets.
	Long-term	▸ Increasing frequency and severity of acute climate impacts may affect delivery of energy through wire infrastructure from assets situated on remote parts of the transmission system and that are at risk due to single points of failure, increasing the value of our strategically located assets.
Response		▸ Capital Power invests in strategically located assets that minimize the risks related to energy delivery that may arise from acute climate change-related events. The value of these assets may increase as they are increasingly used to maintain grid reliability.

Risk and opportunities tables

Chronic

Key assumptions		▸ Water resources are increasingly affected by climate change (impacts vary by jurisdiction). ▸ Water conservation and use are increasingly scrutinized and subject to more stringent regulation. ▸ Long-term changes in weather patterns will affect the design and operation of new and existing renewable assets.
Risks	**Short-term**	▸ Requirements are strengthened to mitigate the chronic impacts of climate change on water resources.
	Long-term	▸ Physical risks associated with climate change, such as changing wind patterns and extreme weather, may reduce the capacity factor of renewable assets. ▸ Water use and conservation requirements may limit physical access to water resources. ▸ Additional investments may be required to manage cooling requirements and operations may be limited due to restrictions on water use.
Mitigation		▸ Monitor developments in policy and regulatory frameworks that address management of water resources. ▸ Risks relating to the regulation and management of water are identified and mitigated in due-diligence processes. ▸ Actively seek opportunities to optimize production from our wind assets. ▸ Monitor water use and implement strategies to reduce consumption at our facilities, which may result in new capital investments and operational costs. Where long-term risk cannot be mitigated, capital allocation may be directed away from high-risk assets and jurisdictions.
Opportunities	**Short-term**	▸ Potential changes in wind patterns and wind regimes may impact operations at our wind facilities and may enable us to generate wind power more efficiently and deliver more renewable energy. ▸ Costs associated with increasing water management requirements may affect supply fundamentals.
	Long-term	▸ Technological advancements in renewables will allow for improved operations in response to persistent changes in climate and weather conditions. ▸ Where long-term changes in climate reduce potential energy output from certain types of assets, there may be increasing value attributed to dispatchable assets with secure fuel sources.
Response		▸ Incorporates climate change-related risk mitigation in the engineering, design and operation of our assets. ▸ Optimizes the energy output and financial performance of our wind assets by increasing our remote monitoring and analytics capabilities. ▸ Proactively manage water resources in line with environmental compliance obligations to ensure we remain competitive in jurisdictions where increasing costs may limit dispatch and competitiveness. ▸ Monitor and invest in operational efficiencies and enhancements that capture additional revenues or mitigate risks that arise from long-term climate-related changes in weather patterns. ▸ Investments in strategically located natural gas assets that are critical to renewable integration and grid support are pursued. ▸ Pursue strategies to ensure assets remain competitive with decarbonization through deployment of low-carbon technologies.

Risk and opportunities tables

Upstream

Key assumptions		▸ Climate change will affect Capital Power's upstream operations and financial results through changing availability and security of fuel sources. ▸ Disruptions to supply chains will become more frequent due to climate change-related events.
Risks	**Short-term**	▸ Increased compliance costs attributed to natural gas use could negatively affect competitiveness of assets and decrease profits. ▸ Increasing stringency of methane regulation could increase costs of production for natural gas and reduce access to reliable fuel sources. ▸ Increased foreign natural gas demand resulting from LNG terminal completion in Kitimat, B.C. may increase commodity price. ▸ Disruption of supply chains due to climate change-related impacts may result in development, operational or financial impacts.
	Long-term	▸ Long-term changes that affect production of natural gas may reduce security of supply and increase cost of fuel. ▸ Development of new pipeline infrastructure may be limited due to regulatory delays and reduced social acceptance. ▸ Changes to wind regimes and solar resources may reduce the revenues and competitiveness of existing resources.
Mitigation		▸ Monitor regulatory developments relating to fugitive methane emissions to assess risks to fuel supply and costs. ▸ Approval and implementation of supply chain management strategies that will support the resiliency and sustainability of our operations. Disruptions to supply chains are managed through contractual provisions for liquidated damages. Alternative supply routes and delivery points are considered to mitigate delivery risk. Local sourcing is used where possible. Consider signing a long-term natural gas offtake. ▸ Direction of capital to optimal locations for renewable development.
Opportunities	**Short-term**	▸ Pursuing digitalization and artificial intelligence technologies will allow companies to capitalize on upstream physical and commercial opportunities associated with climate change and improve adaptation or reduce vulnerability to climate change events. ▸ Securing and optimizing supply chains may mitigate upstream climate risk and improve competitiveness of Capital Power's assets.
	Long-term	▸ Low-carbon fuels are increasingly adopted as an alternative fuel source for new and existing thermal assets. ▸ Sequestration associated with post-combustion capture or direct air capture mitigates the risks of long-term use of natural gas.
Response		▸ Optimize the engineering, design and operation of our assets through the deployment of artificial intelligences strategies at our sites. ▸ Commitment to operational excellence and asset optimization through innovation efforts. ▸ Explore advanced pattern recognition to use data and artificial intelligence to detect patterns that can lead to more efficient and effective maintenance strategies. ▸ Local sourcing is used where possible, positively affecting the communities in which we operate through increased economic opportunities. Benefits are realized through reduced travel times for supplies and lower environmental impacts of transportation and delivery. ▸ Develop strategies to assess and integrate low-carbon technologies at existing facilities, where feasible.

Risk and opportunities tables

Downstream

Key assumptions		▸ Downstream risks from climate change will affect delivery of energy with operational and financial impacts to the power industry. ▸ Corporate entities will increasingly look to procure power from low-emitting sources; the market for corporate power purchase agreements will expand. ▸ Electrification of end-use sectors will support long-term decarbonization.
Risks	**Short-term**	▸ Outages on downstream electricity grids from climate change-related events may cause disruptions to operations, resulting in negative financial impacts to Capital Power. ▸ Potential liability from wildfire risk exacerbated by drought conditions where Capital Power owns transmission/distribution lines.
	Long-term	▸ Markets and operating environments may become more difficult to forecast due to changing climate-driven regulations and policies, which could, in turn, increase volatility of Capital Power's operations and financial results.
Mitigation		▸ Actively manage delivery risks and ensure contingency plans are in place to manage shut-down and short-term cessation of operations as a result of outages on the grid that affect energy delivery. ▸ Strategically located assets are well-suited to supply critical services for restoration events. ▸ Dedicated subject matter expertise, including energy traders, origination specialists, market forecasters, and regulatory and commercial managers who assist in stewarding key issues related to downstream physical risks.
Opportunities	**Short-term**	▸ Increasing investment by corporate entities to secure contracted sources of renewable power to meet their own demand requirements increases the opportunities for development of renewable assets.
	Long-term	▸ Decarbonization through increased electrification will support long-term emission reduction objectives, including net zero commitments.
Response		▸ Pursue contracting opportunities with corporate off-takers to secure the output of new and existing assets. ▸ Development opportunities will grow as electrification of end-use sectors grows. Capital Power is well-positioned to pursue new development opportunities to meet this growing demand.

SASB Index

Table 1. Sustainability disclosure topics & metrics

Greenhouse gas emissions and energy resource planning

SASB disclosure	Category	Unit of measure	SASB disclosure reference	2025 response
Gross global Scope 1 emissions	Quantitative	Metric tonnes (t) CO_2e	IF-EU-110a.1	20,551,362. See the 2025 Integrated Annual Report sustainability appendix for information about our sustainability reporting boundaries and definitions of our assured sustainability performance indicators
Percentage of gross global Scope 1 emissions covered under emissions-limiting regulations	Quantitative	Percentage (%)	IF-EU-110a.1	37%
Percentage of gross global Scope 1 emissions covered emissions-reporting regulations	Quantitative	Percentage (%)	IF-EU-110a.1	100%
Greenhouse gas (GHG) emissions associated with power deliveries	Quantitative	Metric tonnes (t) CO_2e	IF-EU-110a.2	Not applicable. Capital Power only operates power-generating assets and does not own or operate transmission or distribution infrastructure. Therefore, we do not deliver electricity directly to grid-connected retail customers.
Discussion of long- and short-term strategy or plan to manage Scope 1 emissions, emissions reduction targets, and an analysis of performance against those targets	Qualitative	n/a	IF-EU-110a.3	Responsibilities around energy management are outlined in our HSSE Policy, Investment Policy, Enterprise Risk Management Policy and Management Proxy Circular. See the 2025 Integrated Annual Report, Executing our strategic focus and Emissions management sections.

Air quality

SASB disclosure	Category	Unit of measure	SASB disclosure reference	2025 response
Air emissions of the following pollutants: (1) NO_x (excluding N_2O), (2) SO_x , (3) particulate matter (PM10), (4) lead (Pb), and (5) mercury (Hg); percentage of each in or near areas of dense population	Quantitative	Metric tonnes (t), percentage (%)	IF-EU-120a.1	

	NO_x (tonnes/yr)	NO_x	SO_2 (tonnes/yr)	Total PM (tonnes/yr)	Hg (kg/yr)
Air emissions	6,860	6,860	2,719	864	0
% near areas of dense population	62%		79%	79	0

SASB Index

SASB disclosure	Category	Unit of measure	SASB disclosure reference	2025 response
Water management				
Total water withdrawn	Quantitative	Thousand cubic metres (m^3)	IF-EU-140a.1	54,143.83. Notes: Total includes: surface waters, groundwater, seawater, produced waters and third-party waters. Additional contextual information relating to the provided data is outlined in the sites' operating permits, approvals or licenses issued by the regional regulator or from local water quality objectives. We assume water consumed is equal to water withdrawal minus water discharge.
Total water consumed	Quantitative	Thousand cubic metres (m^3)	IF-EU-140a.1	24,765.73. Notes: Total includes: surface waters, groundwater, seawater, produced waters and third-party waters. Operating approvals, permits and/or licenses identify any "discharge consents" or priority substances to be treated specific to each operational site.
Percentage of each in regions with High or Extremely High Baseline Water Stress	Quantitative	Percentage (%)	IF-EU-140a.1	According to the WWF water risk filter, our facilities located in a region with High or Extremely High Baseline Water Stress include La Paloma, Harquahala, and Arlington Valley. These three facilities collectively withdrew 9,156.95 m^3 (17% of total water withdrawals) and consumed 8,986.74 (36% of total water consumption) of water in 2025.
Number of incidents of non-compliance associated with water quality permits, standards and regulations	Quantitative	Number	IF-EU-140a.2	There were no fines or government enforcement actions related to water in 2025.
Description of water management risks and discussion of strategies and practices to mitigate those risks	Discussion and analysis	n/a	IF-EU-140a.3	Standards for the quality and quantity of effluent discharges are determined by applicable regional regulatory agencies. In all cases, our approvals include regulatory requirements, which involve studies, limits, monitoring and reporting. We comply with all conditions in our operating water approvals and participate in watershed alliances and multi-stakeholder watershed management planning initiatives. Capital Power sits on the Alberta Water Council (AWC) Board (a multi-stakeholder partnership to engage industry, NGOs and governments to achieve the outcomes of the Water for Life strategy) as industry vice president, and is a member of the Canadian Electricity Association (CEA), which advocates for the electricity industry positions to the federal government, including protection of fisheries.
Coal ash management				
(1) Amount of coal combustion products (CCPs) generated, (2) percentage recycled	Quantitative	Metric tonnes (t), percentage (%)	IF-EU-150a.1	Not applicable – Capital Power does not have any impoundments that meet the definition for this topic.
Description of coal combustion products (CCPs) management policies and procedures for active and inactive operations	Discussion and analysis	n/a	IF-EU-150a.3	Not applicable – Capital Power does not have any impoundments that meet the definition for this topic.
Energy affordability				
Average retail electric rate for (1) residential, (2) commercial, and (3) industrial customers	Quantitative	Rate	IF-EU-240a.1	Capital Power does not have any residential customers. We do have commercial and industrial customers, however we do not disclose information about these electric rates due to confidentiality constraints.
(1) Number of residential customer electric disconnections for non-payment, (2) percentage reconnected within 30 days	Quantitative	Number, percentage (%)	IF-EU-240a.3	Not applicable – Capital Power does not serve as a regulated public utility responsible for managing residential customer connections, disconnections or reconnections.
Discussion of impact of external factors on customer affordability of electricity, including the economic conditions of the service territory	Discussion and analysis	n/a	IF-EU-240a.4	Our strategy prioritizes safely delivering reliable and affordable power. For more information about our strategy, see the Executing our strategic focus section of the 2025 Integrated Annual Report.

SASB Index

SASB disclosure	Category	Unit of measure	SASB disclosure reference	2025 response
Workforce health and safety				
(1) Total recordable incident rate (TRIR), (2) fatality rate, and (3) near miss frequency rate (NMFR) for (a) direct employees and (b) contract employees	Quantitative	Rate	IF-EU-320a.1	TRIF: 0.472 Fatality rate: 0 NMFR: 4.72 See the 2025 Integrated Annual report sustainability appendix for information about our sustainability reporting boundaries and definitions of our assured sustainability performance indicators.
End-use efficiency and demand				
Average retail electric rate for (1) residential, (2) commercial, and (3) industrial customers	Quantitative	Number, percentage (%)	IF-EU-420a.1	Not applicable – Capital Power is not a regulated public utility.
Percentage of electric load served by smart grid technology	Quantitative	Percentage (%) by megawatt hours (MWh)	IF-EU-420a.2	Not applicable – Capital Power only operates power generation assets and does not own or operate transmission or distribution infrastructure.
Customer electricity savings from efficiency measures, by market	Quantitative	Megawatt hours (MWh)	IF-EU-420a.3	Not applicable – Capital Power does not sell to a material number of direct customers.
Nuclear safety and emergency management				
Total number of nuclear power units, broken down by results of most recent independent safety review	Quantitative	Number	IF-EU-540a.1	Not applicable – Capital Power does not own or operate any nuclear power units.
Description of efforts to manage nuclear safety and emergency preparedness	Discussion and analysis	n/a	IF-EU-540a.2	Not applicable – Capital Power does not own or operate any nuclear power units.
Grid resiliency				
Number of incidents of non-compliance with physical or cybersecurity standards or regulations	Quantitative	Number	IF-EU-550a.1	Capital Power has not experienced any financial losses related to technology failure, cyber-attacks or security breaches.
(1) System Average Interruption Duration Index (SAIDI), (2) System Average Interruption Frequency Index (SAIFI), and (3) Customer Average Interruption Duration Index (CAIDI), inclusive of major event days	Quantitative	Minutes, number	IF-EU-550a.2	Not applicable – Capital Power only operates power generation assets and does not own or operate transmission or distribution infrastructure. Capital Power's fleetwide availability in 2025 was 91%.

SASB Index

Table 2. Activity Metrics

Activity metrics	Category	Unit of measure	SASB disclosure reference	2025 response
Number of: (1) residential, (2) commercial, and (3) industrial customers served	Quantitative	Number	IF-EU-000.A	Capital Power had approximately 203 commerical and industrial customers in 2025.
Total electricity delivered to: (1) residential, (2) commercial, (3) industrial, (4) all other retail customers, and (5) wholesale customers	Quantitative	Megawatt hours (MWh)	IF-EU-000.B	See Business report, 2025 Integrated Annual Report.
Length of transmission and distribution lines	Quantitative	Kilometres (km)	IF-EU-000.C	Not applicable – Capital Power does not own or operate any transmission or distribution infrastructure.
Total electricity generated, percentage by major energy source, percentage in regulated markets	Quantitative	Megwatt hours (MWh), percentage (%)	IF-EU-000.D	See Business report, 2025 Integrated Annual Report.
Total wholesale electricity purchased	Quantitative	Megawatt hours (MWh)	IF-EU-000.E	Not applicable – Capital Power does not purchase a significant amount of wholesale electricity for physical consumption.

Sustainability appendix

Sustainability reporting boundaries

Scope 1 emissions and emissions intensity

For Scope 1 emissions and emissions intensity data, we report based on the GHG Protocol's operational control approach, meaning we report only on assets that we operate (unless otherwise stated) and emissions data disclosed represents material sources of emissions from all facilities within our boundary.

Data from Joffre and Shepard Energy Centre, units we hold an ownership interest in, are not included in our reporting boundary because we do not hold the operating permits, and therefore do not have operating control of the facility.

The boundary of Capital Power sites expanded to reflect the acquisition of Hummel Station and Rolling Hills Generating Station. Full year emissions and intensity are included in the inventory.

Gases included in calculation of absolute Scope 1 emissions include CO_2, CH_4, N_2O, and SF_6. Global warming potential rates used are from IPCC Guidelines (AR5) for Greenhouse Gas Inventories. We use a combination of mass balance and emission factors in the calculation of CO_2 emissions. Quantification requirements are dictated by the operational jurisdiction.

Capital Power follows GHG Protocol guidance to report emissions and other environmental data for the entire reporting year. As per the GHG Protocol, we disclose emissions data for direct CO_2 emissions from biomass separate from other emissions. In 2025, biomass emissions were 5,702 tCO_2e.

Scope 2 emissions

Scope 2 emissions are quantified based on the purchased or imported power at each site and location-based emission factors for electricity intensity. Location-based emission factors in Canada are taken at the provincial level from the latest National Inventory Report. Location-based emission factors in the United States are based on sub-regional grid emission intensities from the Environmental Protection Agency's e-GRID publications.

TRIF

In accordance with occupational health and safety legislation, Capital Power records and reports all health and safety events that are legally reportable at work areas where Capital Power has full care, custody, and control of the work area, the work, and the workers.

TRIF is an internal reporting metric that is independent of, and does not replace, any legislated obligations. The Operational TRIF presented in this report includes recordable occupational injuries involving employees and contractors within corporate and operational environments where Capital Power directs the work and supervises the workers. Construction related events, while reported to regulators as required and monitored internally, are excluded from Operational TRIF because construction activity is outside the scope of core operations and varies significantly between years.

Gender diversity

Capital Power's gender diversity data reflects employees who self-identified their gender as woman or man at the time of onboarding and includes all permanent, temporary, temporary extended, and casual employees, as well as employees on maternity or parental leave, as of December 31, 2025. Contractors, pensioners, Board members, students, and employees on long-term disability are excluded. As of year-end 2025, women represented 43% of the Executive team and 24% of the overall employee population.

Sustainability appendix

Revisions/restatements of information

We follow GHG Protocol guidance to revise historic emissions in the event of structural changes to the organization (acquisitions, divestments, mergers) and/or changes in calculation methodology, and restate emissions in the event of the discovery of errors in previously reported data that would otherwise compromise the consistency and relevance of the reported GHG emissions information. We revise/restate emissions if the effect of expected changes exceeds our quantitative threshold of +/- 10 per cent of base year or other historical emissions.

Scope 1 emissions and emissions intensity disclosed in this report have been revised to reflect the acquisition of our Hummel Station and Rolling Hills facilities which were acquired on June 5, 2025.

Revisions due to structural changes have resulted in an increase in past years' reported emissions when compared to reporting from previous years. These adjustments are reflected in Scope 1 absolute emissions and intensity only, other metrics have not been adjusted.

The revised absolute Scope 1 emissions disclosed in this report are as follows:

- 2021: Revision from 15,627,451 tCO_2e to 18,736,480 tCO_2e
- 2022: Revision from 18,112,740 tCO_2e to 22,011,857 tCO_2e
- 2023: Revision from 18,751,151 tCO_2e to 23,271,298 tCO_2e
- 2024: Revision from 17,431,328 to 21,538,766 tCO_2e

The revised emissions intensities disclosed in this report are as follows:

- 2021: Revision from 0.51 to 0.49 tCO_2e/MWh
- 2022: Revision from 0.50 to 0.49 tCO_2e/MWh
- 2023: Revision from 0.47 to 0.46 tCO_2e/MWh

External assurance definitions

Definitions of subject matter and applicable criteria related to assured sustainability performance indicators include:

- Total Scope 1 GHG emissions (tCO_2e): Scope 1 emissions, as defined by the GHG Protocol, for all facilities included within our emissions reporting boundary.
- Scope 1 Greenhouse gas intensity (tCO_2e/MWh): Total scope 1 absolute emissions, as defined by the GHG Protocol, divided by total net generation (MWh) for all facilities included within our emissions reporting boundary.
- Net generation: The amount of electricity a power plant supplies to the power transmission line connected to the power plant.

10-year operational and financial highlights

(millions of dollars except per share and operational amounts) (unaudited)

	2025	2024	2023	2022	2021	2020	2019	2018	2017	2016
OPERATIONAL										
Number of facilities at year-end[1]	**32**	30	30	29	26	28	26	25	24	18
Electricity generation (GWh)	**44,616**	37,821	32,487	28,573	22,811	23,806	24,527	20,229	17,194	15,328
Facility availability	**91 %**	92%	95%	93%	90%	95%	94%	95%	96%	94%
Financial Position (at December 31,)										
Total assets[2]	**$15,441**	$12,930	$11,156	$10,133	$9,073	$8,911	$8,582	$7,569	$6,819	$6,062
Loans and borrowings including current portion	**$6,730**	$4,976	$4,716	$3,726	$3,360	$3,552	$3,413	$2,647	$2,146	$1,508
Income and Cash Flow										
Revenues and other income[2]	**$3,720**	$3,776	$4,282	$2,983	$1,990	$1,937	$1,963	$1,417	$1,168	$1,214
Adjusted EBITDA[2,3,6,7,8]	**$1,580**	$1,333	$1,455	$1,353	$1,124	$955	$1,029	$736	$614	$509
Net income[6]	**$159**	$701	$737	$168	$87	$130	$119	$258	$125	$102
Net income attributable to shareholders[2]	**$160**	$699	$744	$178	$98	$136	$125	$265	$135	$111
Basic earnings per share[2]	**$0.88**	$5.16	$6.07	$1.19	$0.39	$0.78	$0.73	$2.17	$0.98	$0.91
Diluted earnings per share[2,4]	**$0.88**	$5.15	$6.04	$1.19	$0.39	$0.77	$0.72	$2.16	$0.98	$0.91
Net cash flows from operating activities	**$962**	$1,144	$822	$935	$867	$611	$720	$450	$372	$375
Adjusted funds from operations[3,5,8]	**$1,066**	$824	$821	$848	$605	$522	$555	$397	$361	$291
Adjusted funds from operations per share[3,5,8]	**$7.08**	$6.38	$7.01	$7.28	$5.40	$4.96	$5.32	$3.85	$3.58	$3.02
DIVIDENDS										
Dividends declared per common share	**$2.69**	$2.53	$2.39	$2.26	$2.12	$1.99	$1.86	$1.73	$1.62	$1.51
Common Share Information (TSX:CPX)										
High	**$73.80**	$68.73	$46.90	$51.90	$45.05	$38.88	$35.09	$29.79	$26.51	$24.49
Low	**$41.87**	$33.90	$35.11	$36.65	$33.31	$20.23	$26.22	$22.15	$23.15	$16.37
Close	**$58.55**	$63.72	$37.84	$46.33	$39.46	$34.98	$34.39	$26.59	$24.49	$23.23
TSX volume (millions)	**202.1**	125.8	90.4	93.1	73.3	103.1	77.1	65.4	62.8	73.2

1 In June 2025, the Company acquired Hummel Station, LLC, owner of the 1,124 MW Hummel combined cycle natural gas facility in Shamokin Dam, Pennsylvania, and Rolling Hills Generating, LLC, owner of the 1,023 MW Rolling Hills Generation plant, a combustion turbine natural gas facility in Wilkesville, Ohio.

2 The comparative periods' amounts for 2017 and 2018 have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16 in 2019. Comparative period amounts prior to 2017 have not been restated.

3 The consolidated financial highlights, except for adjusted EBITDA, adjusted funds from operations (AFFO) and AFFO per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures and Ratios in the Business report.

4 Diluted earnings per share was calculated after giving effect to outstanding share purchase options and the exchange of common limited partnership units of CPLP held by EPCOR for common shares of Capital Power on a one-for-one basis.

5 Commencing in 2017, the Company uses AFFO as a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, debt repayments and common share dividends to the Company's shareholders. In 2018, the Company made several adjustments to its AFFO measure to better reflect the purpose of the measure, see adjusted funds from operations and adjusted funds from operations per share section in the Non-GAAP Measures and Ratios section of the Business report for further details around the calculation of AFFO. Comparative AFFO figures have been restated to reflect the above refinements to the AFFO metric.

6 Adjusted EBITDA figures for 2016 to 2018 have been restated to correspond to the 2019 basis of presentation.

7 In 2023, the Company refined its adjusted EBITDA measure to better reflect the purpose of the measure, excluding other items affecting facility operations that are not reflective of the long-term performance of the Company. Comparative figures have not been restated.

8 In 2025, the Company refined its adjusted EBITDA and AFFO measures to better reflect the purpose of the measures, excluding acquisition and integration costs that are not reflective of the long-term performance of the Company. Comparative figures for 2024 and 2023 have been restated to reflect the refinements. Comparative periods prior to 2023 have not been restated.

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Auditors

KPMG LLP, Edmonton, Alberta

Stock Exchange and Index Membership

Toronto Stock Exchange (TSX)
Member of the following indices:

- S&P/TSX Composite
- S&P/TSX Canadian Dividend Aristocrats
- S&P/TSX Capped Utilities
- S&P/TSX SmallCap

Stock trading symbols (TSX)

Common shares: CPX

Preferred shares:
Series 1 – CPX.PR.A
Series 3 – CPX.PR.C
Series 5 – CPX.PR.E

Common Shares
(as of December 31, 2025)

Total outstanding shares: 155,962,899

Market capitalization: $9.1 billion

2026 Expected Common Share Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
Quarter 1	Mar 30	Mar 31	Apr 30
Quarter 2	Jun 29	Jun 30	Jul 31
Quarter 3	Sept 28	Sept 29	Oct 30
Quarter 4	Dec 30	Dec 31	Jan 29, 2027

2026 Expected Preferred Shares Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
Quarter 1	Mar 17	Mar 18	Mar 31
Quarter 2	Jun 16	Jun 17	Jun 30
Quarter 3	Sept 15	Sept 16	Sept 29
Quarter 4	Dec 15	Dec 16	Dec 31

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