2024 Integrated Annual Report

Powering the energy expansion

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 2025, are integrated into the Introduction and Powering the energy expansion 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, 2024, through to December 31, 2024, 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 February 25, 2025.

We welcome your feedback on our report at info@capitalpower.com.

KPMG assurance

Capital Power engaged KPMG LLP to provide independent limited assurance on select performance information within this report. The symbol ☑ indicates metrics that have been assured for 2024. KPMG's limited assurance report is on pages 91-95. 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 179.

Territorial acknowledgement

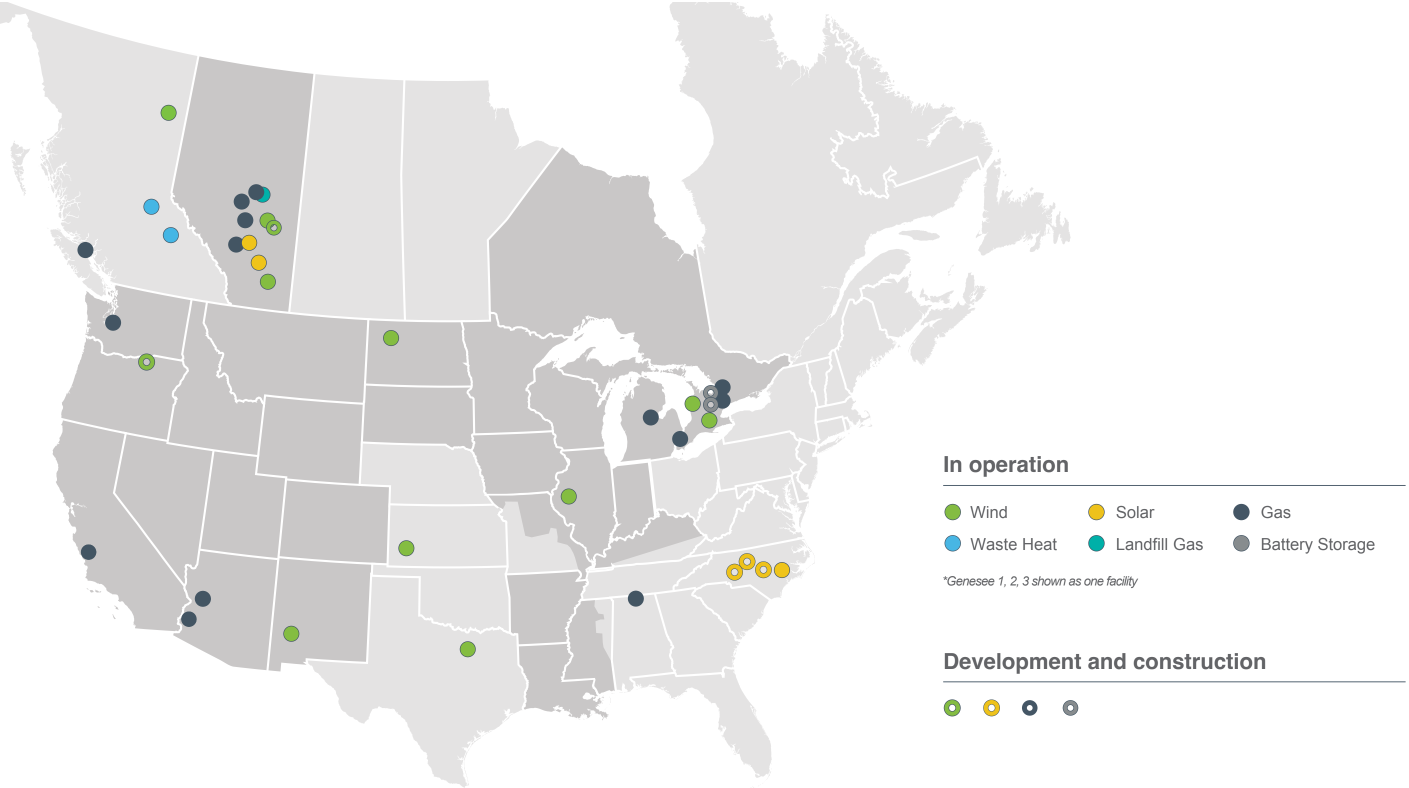
In the spirit of reconciliation, Capital Power respectfully acknowledges that we operate within the ancestral homelands, traditional and treaty territories of the Indigenous Peoples of Turtle Island, or North America. Our head office is located within the traditional and contemporary home of many Indigenous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

About us

Powering Change by Changing Power™

As a growth-oriented power producer, we prioritize safely delivering reliable and affordable power, building lower-carbon power systems, and creating balanced energy solutions.

As a group of experts and innovators in our field, we work to deliver power for communities across Canada and the U.S. through the development, acquisition, ownership and safe operation of our renewable and thermal power generation facilities. Currently, Capital Power[1] owns approximately 10 GW of power generation capacity at 30 facilities.



Deliver

~10 GW

owned generation capacity

Build

~$500M

committed growth and enhancement capital expenditures for 2025

Create

Balanced energy solutions

Provide integrated energy solutions to commercial and industrial customers

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[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 indicates, means Capital Power Corporation together with its subsidiaries.

Board Chair and CEO letter

Energizing the North American energy expansion

A message from Jill Gardiner, Board Chair, and Avik Dey, President and CEO

In 2024, Capital Power successfully delivered on our strategy and is now positioned to lead the energy expansion.[1]

Now is the time to power change

Population growth, industrial reshoring, economy-wide electrification and artificial intelligence (AI) have transformed the electricity sector from an energy transition to a full-on energy expansion – driving a crucial need for more reliable and affordable power.

At Capital Power, we see this as a tremendous opportunity. Guided by our strategy, we are more prepared than ever to deliver the balanced energy solutions North America needs. While we are investing in a diverse mix of solutions, including flexible generation, renewables, and the advancement of lower-carbon solutions, we believe that natural gas will remain critical to grid reliability and affordability for the foreseeable future. Natural gas is an effective pathway to lower-carbon generation that facilitates growth in batteries and renewables and allows us to eliminate our reliance on coal in our markets.

Energizing economies with balanced solutions

In 2024, we proudly achieved combined cycle commercial operations of our Genesee Repowering project in Alberta, transforming the facility from **coal to 100% natural gas** five years ahead of the Alberta government mandate. This transformation made our Genesee facility Canada's most efficient natural gas combined cycle plant.[2] The advancement of this industry-leading $1.6 billion initiative increases the overall capacity at the Genesee Generating Station by 512 megawatts (MW) while reducing Scope 1 greenhouse gas (GHG) emissions by 3.4 million tonnes (Mt) annually.[3]

Capital Power is optimizing and expanding our assets and is well-funded and prepared to acquire new assets in key strategic markets to meet growing demand. In May 2024, we opened our regional U.S. headquarters in Phoenix, Arizona, to support the increasing demand for power in high-growth U.S. markets. We are growing our base of flexible generation assets in the U.S., each offering unique development and expansion opportunities.

This includes expanding our presence in the rapidly growing U.S. Western Electricity Coordinating Council (WECC) market by acquiring and integrating[4] our Harquahala and Frederickson 1 natural gas-fired assets. We are also on track to integrate our La Paloma asset in 2025. Together with our other U.S. assets, they demonstrate the success of our geographic diversification strategy, with approximately half of our 2024 adjusted EBITDA contribution coming from our U.S. facilities for the first time.

On the renewables front, we advanced and are nearing completion of our 126-MW Halkirk 2 Wind project in Alberta. As part of our commitment to reconciliation, we began a partnership with the four Maskwacis First Nations, which includes an opportunity for them to acquire 25% of Halkirk 2 Wind after three years. Additionally in the U.S., we continued to advance development of our **Maple Leaf Solar** project and executed 25-year power purchase agreements (PPAs) for our **Hornet Solar** and **Bear Branch Solar** projects, totalling ~180 MW of solar generation capacity in development.

Energy storage will be increasingly vital to grid reliability, enabling greater integration of renewable energy and managing peak demand. We have begun constructing battery energy storage systems (BESS) in Ontario at our **York Energy** and **Goreway Power Station** facilities.

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1 Energy expansion refers to the increase in overall grid capacity to produce and deliver energy required to meet unprecedented demand for reliable, affordable, and cleaner power.

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

3 Anticipated annual GHG emission reductions from Genesee Repowering project and transition off coal compared to 2019 facility emissions.

4 Full integration includes operations and people. Operational integration involves, systems, processes, and technology while people integration includes onboarding the workforce as Capital Power employees, organizational alignment and alignment of management practices. By December 31, 2024, Frederickson 1 was fully integrated, Harquahala was operationally integrated, and La Paloma is expected to be operationally integrated in 2025.

Board Chair and CEO letter

These systems are expected to provide up to 170 MW of power storage and are expected to reach commercial operation in mid-2025, helping the province meet the growing demand for power in key urban areas.

These significant achievements from the past year have strengthened our position as a leading power producer in North America. Together, they demonstrate how, through our diversified, balanced approach, we are prepared to meet this tremendous era of growth and the need for reliable, affordable, and cleaner energy.

Guiding our success

Our experienced Board of Directors ensures our strategy and execution align with our North Star—*Powering Change by Changing Power*™. Guided by our robust corporate governance policies, the Board provides independent, effective oversight and leadership to support the Executive Team as they focus on sustainably growing shareholder value. With broad and diverse expertise and experience, our Board brings a significant depth of knowledge to facilitate Capital Power's journey.

In 2024, we were pleased to welcome two new members, Neil H. Smith and George Williams. Neil and George both bring leadership expertise and deep industry operational and market experience that will be invaluable to our Board. With Doyle Beneby's retirement from the Board, we thank him for his guidance and wish him the best.

It is with deep sorrow that we acknowledge the passing of Bryan DeNeve, SVP, Chief Commercial Officer, in January 2025. As an executive who was instrumental in the foundation and success of Capital Power, Bryan's leadership helped shape the Company's growth and achievements across various areas, including commercial and business development, operations, and finance. His vision, dedication, leadership and commitment to excellence will be remembered by all who had the privilege of working with him. Our heartfelt condolences go out to Bryan's family, friends, and colleagues.

Excellence in action

Powering Change by Changing Power™ requires investment and dedicated, highly skilled teams inspired by challenge and innovation. Our team has deep-rooted expertise in operating grid-scale power generation assets, strategically assessing market dynamics and regulatory structures, and commercial management to drive long-term value from our fleet.

In 2024, we enhanced our operational efficiency by optimizing our corporate structure. This action accelerated the execution of our strategy and positions our business for long-term success. We are streamlined, ready to scale, and competitively positioned to capture the immense market opportunity in North America.

As we grow our Company across North America, we prioritize strong relationships across operating communities by giving back where we live and work. In 2024, we provided $3.7 million to climate action, equity and opportunity, and wellbeing-focused charitable organizations and causes most important to our employees, partners, and neighbours.

Looking ahead

With the energy expansion upon us, Capital Power has multiple ways to create shareholder value and capitalize on this immense opportunity for growth, transformation, and innovation. Our track record of success lays the foundation for our future and will accelerate our momentum into 2025.

Our expertise and high-availability assets position us to provide power for the growing build-out of data centres in North America. In particular, we are excited about the opportunity to bring a data centre to Alberta at one of the most compelling sites in North America, our Genesee Generating Station site, to deliver power at scale in the near future.

We have considerable opportunity to create shareholder value across our strategically positioned fleet of assets. Our focus in 2025 will be contracting our existing assets, expansion and optimization of our fleet, acquisition of incremental U.S. flexible generation capacity, and development of renewables.

As we execute on our priorities, we will continue to prioritize cash flow per share growth, disciplined capital allocation and financial stability. We are well positioned to grow while maintaining our investment-grade credit rating and delivering our targeted average annual total shareholder return of 12-14%.

We thank all our communities and stakeholders for their ongoing support and collaboration, our employees for their dedication to excellence across our business, and our Board and Executive Team for their guidance and leadership.

Sincerely,

Jill Gardiner
Board Chair

Avik Dey
President and
Chief Executive Officer

2024 performance highlights

Delivering strong results with purpose

In 2024, we delivered strong financial results through our diversified generation fleet, with significant share price appreciation resulting in a total shareholder return of ~80%, including our 11th consecutive annual dividend increase. Further, we have increased our liquidity through asset rotation and successful debt and equity raises. Refer to the Financial highlights section of the Business report for more information on our financial performance.

We are proudly the fifth-largest natural gas independent power producer in North America after acquiring and integrating ~2 GW of U.S. capacity in 2024. Our strategically located assets supported strong results from our U.S. portfolio in 2024, with roughly half of our capacity and adjusted EBITDA contributions coming from our U.S. facilities for the first time in our Company's history.

We also continued to invest in innovative solutions to decarbonize power, including advancing our transformational Genesee Repowering project. This marks Capital Power's transition off coal more than five years ahead of the Alberta government mandate and will result in 3.4 Mt[1] in annual Scope 1 GHG emission reductions.

Growth

Additional ~2 GW of flexible generation

Value

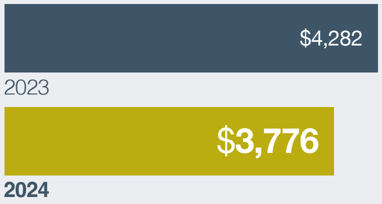
~80% Total Shareholder Return (TSR) in 2024

Diversification

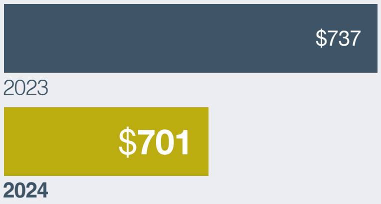
50/50 capacity across Canada and U.S. assets

Decarbonization

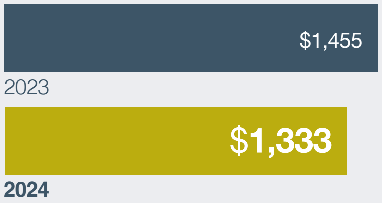
~3.4 Mt[1] annual emission reductions at Genesee Generating Station



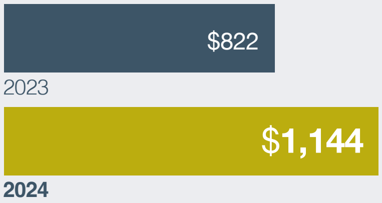
Revenues and other incomes ($M)



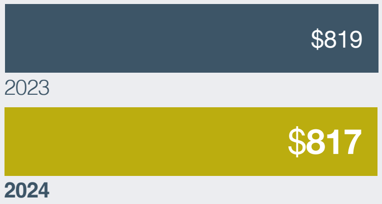
Net income ($M)



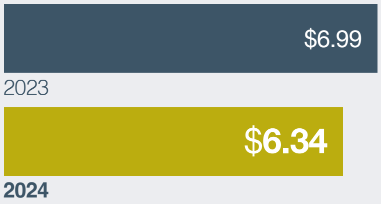
Adjusted EBITDA ($M)[2]



Net cash flow from operating activities ($M)



Adjusted funds from operations ($M)[2]



Adjusted funds from operations per share ($)[2]

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[1] Anticipated annual GHG emission reductions from Genesee Repowering project and transition off coal compared to 2019 facility emissions.

[2] See Non-GAAP financial measures and ratios, Business report.

2025 performance targets

Priority	2025 target[1]
Deliver	
Execution of major turnarounds	Sustaining capital expenditures of **$195 million to $225 million**
Generate financial stability and strength	Adjusted fund from operations[2,3] of **$850 million to $950 million**
	Adjusted EBITDA[2,3] of **$1,340 million to $1,440 million**
Portfolio optimization	Re-contract/contract flexible generation
	Maximize facility asset life and value
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
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
Create	
Balanced energy solutions	Evaluate Small Modular Reactors (SMRs) in Alberta
	Provide integrated energy solutions to commercial and industrial customers

[1] Performance targets for 2025 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] The Alberta commercial portfolio position, contracted prices and forward Alberta pool and natural gas prices for 2025, 2026, and 2027 (all as at December 31, 2024) are outlined in the table below. These hedged volumes and weighted average prices approximate the values used to inform our 2025 guidance. The remaining Alberta commercial power and natural gas volumes were valued based on an average forward Alberta pool price of $57 per MWh and AECO natural gas price of $2.70 per GJ.

[3] Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP financial measures and ratios.

Alberta commercial portfolio	**2025**	2026	2027
Power			
Hedged volume (GWh)	**11,500**	11,000	5,500
Weighted average hedged prices[a] ($/MWh)	**High-$70s**	High-$70s	Low-$80s
Forward Alberta power prices ($/MWh)	**$48**	$53	$60
Natural gas			
Hedged volume (TJ)	**75,000**	70,000	40,000
Weighted average hedged prices[a,b] ($/GJ)	**< $3**	< $4	< $4
Forward Alberta gas prices ($GJ)	**$1.90**	$2.90	$3.00

[a] Forecasted average contracted prices may differ significantly from future average realized prices as future realized prices are driven by a combination of previously contracted prices and settled prices. When long-term forward portfolio optimization hedges are transacted, they reflect the market's expectations for future period pricing.

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

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

Executing our strategy

The energy expansion is upon us. As we enter this tremendous era of growth, our diverse generation footprint is uniquely positioned to meet the demand for reliable, affordable and lower-carbon energy.

Positioned for growth

Power sector fundamentals across North America are stronger than ever. The unprecedented energy expansion is multi-faceted with power demand growing from commercial, industrial and residential customers due to AI, electrification, industrial reshoring, and population growth.

Energy expansion and AI

Data centres have emerged as a transformative force and are increasingly being built to support AI. At a time when North American power demand is seeing growth from multiple sources, the prospect of commercially viable AI products has contributed to creating unprecedented demand growth that many local grids will have limited ability to support.

In fact, experts predict that data centre electricity consumption will double by 2030, reaching ~80 GW[1] of capacity. This is layered on top of the roughly ~2%[1] compounded annual growth in total U.S. power demand anticipated from residential, commercial and industrial customers, and transportation electrification.

Our strategy

Capital Power's portfolio is uniquely positioned to help meet the growing demand for reliable, affordable, and lower-carbon energy with our geographically diverse mix of merchant and contracted flexible generation coupled with renewables, and a strong pipeline of growth. We aim to scale the business, deepen our presence in the U.S., and provide balanced energy solutions that customers need.

Our primary focus remains on investing in our core business lines. This includes flexible generation through contract optimization and expansion through acquiring assets in U.S. markets; developing renewables through selective growth; and trading and originating with our highly skilled in-house expertise.

	Business line	**Deliver** Established business with cash flow	**Build** Greenfield & brownfield expansion	**Create** Balanced energy solutions
Core Business	**1** **Flexible Generation**	Optimize current fleet, acquire new flexible generation assets in key U.S. markets	Expand firm capacity, build utility-scale storage	**4** Provide integrated energy solutions to commercial and industrial customers
	2 **Renewables**	Evaluate asset recycling opportunities	U.S. solar expansion, wind projects that support balanced energy solutions	
	3 **Trading & Origination**	Expand activity around existing fleet		
Beyond	**New Value Creation Pathways**	Employ proven technologies to reduce emissions and build new business lines across the power value chain		

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[1] According to the Energy Information Administration (EIA).

Delivering reliable and affordable power

Through our balanced approach to generation, we are working with customers and partners to support reliability and affordability.

Off-coal milestone achieved

We celebrated a milestone in lower-carbon energy innovation in 2024 with the successful transition of our Genesee Generating Station from **coal to 100% natural gas**. The Genesee Repowering Project will reduce our GHG emissions by 3.4 Mt annually[1] while increasing dispatchable generation with the addition of 512 MW of net-high efficiency and low-heat rate capacity.

Our Genesee Generating Station, which has delivered reliable and affordable power to Alberta for over 30 years, is now Canada's most efficient natural gas combined cycle plant.[2] This achievement, comes five years ahead of the Alberta government mandate, demonstrating our ability to transform our existing infrastructure to support the long-term transition to lower-carbon energy, while delivering strong shareholder value.

Expanding in the U.S.

In 2024, we delivered on our grid-critical natural gas strategy by integrating two of three recently acquired[3] natural gas-fired generation facilities (see Significant events). Our Frederickson 1, La Paloma, and Harquahala facilities provide on-demand flexibility and reliability and help maintain grid stability in the transition to a lower-carbon energy future. Each asset is well-positioned in high-demand areas of the U.S. WECC market and will support further development opportunities in the region.

In support of our expanding presence in the U.S., we established our regional U.S. headquarters in 2024 in Phoenix, Arizona. This new office will support our large U.S. power generation portfolio – including two major natural gas assets in the state.

Delivering operational excellence

Capital Power has consistently demonstrated operational excellence through a commitment to efficiency and innovation. We have built our Company on long-term investment in our fleet and manage our assets to extract long-term value. This strategy does not only benefit our equipment, but it has created a culture of deep ownership and pride, which further drives high performance and innovation.

We continuously work to execute high standards for asset planning, performance and safety to deliver reliability and reduce asset downtime. The depth of our internal expertise is backed by our commitment to operational excellence. We continually seize opportunities to build fleetwide efficiencies by:

- Increasing our output and achieving higher capacity factors through operational decisions, equipment upgrades and process enhancements.
- Delivering reliability and reducing downtime and operational and management costs by applying our expertise in operations, turnarounds, and optimization.
- Optimizing our use of fuel, water, and other resources.

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1 Anticipated annual GHG emission reductions from Genesee Repowering project and transition off coal compared to 2019 facility emissions.

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

3 The La Paloma acquisition and the Harquahala acquisition closed on February 9, 2024 and February 16, 2024, respectively. The Frederickson 1 acquisition closed on December 28, 2023.

Building lower-carbon power systems

Optimizing our facilities and building new capacity is foundational to ensuring we can deliver reliable and affordable power today, while preparing to meet growing power demand for tomorrow.

Advancing battery energy storage systems in Ontario

To support grid reliability and meet increasing energy demand in Ontario, Capital Power is constructing two BESS systems in response to the Independent Electricity System Operator's (IESO) call for new power generation and capacity in high priority areas. These systems will not only support the integration of renewable energy but will also enhance grid reliability and provide backup power when needed.

In 2024, Capital Power began construction of two BESS installations at our York Energy and Goreway facilities, with each system being capable of producing 120 MW and 50 MW of power storage and output, respectively. Commercial operation of both BESS projects is anticipated in 2025.

Expanding and optimizing facilities to meet demand

Optimizing our facilities is foundational to ensuring we can deliver reliable and affordable power today, while preparing to meet growing power demand for tomorrow. In response to the IESO's expedited request for capacity in Ontario, we are investing in expansion and upgrade projects at our East Windsor, Goreway, and York Energy facilities.

Our East Windsor Expansion project will add up to ~100 MW of capacity through the addition of a new gas turbine generator. Designed to operate as a peaking facility, the project will provide dependable capacity when it is most needed.

Additionally, upgrade projects at our Goreway and York Energy facilities will provide operational flexibility and an additional combined ~80 MW of generation capacity. These projects in total will provide an additional ~180 MW of capacity to the Ontario grid to meet the immediate, and growing, demand for reliable and affordable power.

Progressing solar

We continue to progress development of our Hornet Solar, Bear Branch Solar, and Maple Leaf Solar projects. In June 2024, we successfully executed 25-year PPAs with Duke Energy Carolinas for the Hornet Solar and Bear Branch Solar projects. Construction of Hornet Solar began in August 2024, with construction expected to begin for Bear Branch Solar and Maple Leaf Solar in 2025. These projects will provide a total generation capacity of ~180 MW once complete.

Building wind capacity

In 2024, we made significant progress on the construction of our new Halkirk 2 Wind facility and entered into a three-year partnership and equity option agreement with the four Maskwacis First Nations (see Significant events).

Halkirk 2 Wind will support a 15-year virtual power purchase agreement (VPPA) with Saputo Inc., a global leader in the food industry. Subject to final regulatory approvals and once operational, the portion of the wind facility contracted by Saputo will generate approximately 206,300 MWh of renewable electricity per year.

We previously announced a 23-year electricity supply agreement with Public Services and Procurement Canada. Once Halkirk 2 Wind becomes operational, the facility will begin providing renewable energy in support of the Government of Canada's commitment to power all federal buildings with 100% clean[1] electricity.

Driving decarbonization in Alberta

We commissioned our Genesee Repowering project at the end of 2024, ending coal-fired generation five years ahead of the Alberta government mandate and reducing emissions by 3.4[2] Mt annually. Our investment of $1.6 billion demonstrates our commitment to a lower-carbon future.

Additionally, Capital Power and Ontario Power Generation (OPG) are proud to be pioneering a two-year feasibility study for nuclear small modular reactors (SMRs) in Alberta. SMRs are seen as having significant potential as a non-emitting energy solution in Canada. In 2024, Capital Power qualified for $13 million in funding from the Government of Canada that will support activities in the feasibility study. See **www.albertasmr.ca** for details.

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[1] Public Services and Procurement Canada's **definition** of clean power is "electricity that is produced from non-greenhouse gas emitting energy sources".

[2] Anticipated annual GHG emission reductions from Genesee Repowering project and transition off coal compared to 2019 facility emissions.

Creating balanced solutions for our energy future

We are working to meet the growing demand for energy while tackling the urgent challenge of climate change by delivering grid-critical capacity, pursuing lower-carbon power solutions, and making strategic investments to optimize our existing power generation assets.

Powering change with balanced energy solutions

We have the responsibility and expertise to help lead North America's transition to a lower-carbon economy while providing our customers and communities with access to reliable and affordable power during this time of energy expansion.

When we established our GHG emissions sustainability targets beginning in 2018, the world had not anticipated the unprecedented and ongoing growth of AI, manufacturing, and electrification. Together, these drivers are expected to double energy demand by 2050.

In late 2024, we reassessed our 2030 interim[1] and 2045 net zero targets considering projected market conditions as well as our corporate strategy. Based on this assessment and our continued commitment to providing reliable and affordable energy to our customers and communities, we will not meet these targets.

As a result, we have made the decision to retire both our interim and net zero targets and refresh our approach to sustainability to concentrate on purposeful actions that will directly improve our sustainability performance. This approach focuses on investments in lower-carbon solutions and will allow Capital Power to continue to meet the power needs of the energy expansion while simultaneously addressing long-term sustainability objectives.

The Company has developed a roadmap for advancing towards a lower-carbon future while meeting the immediate need for reliable and affordable power. Aligned with our corporate strategy, we are well-positioned to continue supporting the lower-carbon transition in our markets while meeting today's and tomorrow's energy needs. Our strategy is working to deliver more energy while scaling up lower-carbon solutions and reducing our emissions. We will continue to transparently report our progress every year and have maintained internal ESG-linked compensation targets to support our advancement towards a lower-carbon future.

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

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[1] Our previously stated 2030 interim targets include: Reducing Scope 1 emissions at Genesee by 50% from 2005 levels; reducing Scope 1 emissions by 10% from 2005 levels, based on our 2019 fleet; reducing Scope 1 emissions intensity by 65% from 2005 levels, and constructing all new natural gas generation units to be carbon capture and/or hydrogen ready.

Governance and risk management

Operating a responsible business guided by transparency, integrity, and accountability is fundamental to who we are and to earning and maintaining the trust of our stakeholders.

Corporate governance

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

Board governance

The effectiveness of our corporate governance starts with our Board, whose integrity, skill, and experience ensure that what we do is consistent with our values and supports good decision making in the interest of our stakeholders. Our Board adopts corporate governance policies and practices that set expectations and accountabilities, ensuring our business is conducted ethically and effectively.

Our independent directors provide effective leadership, guidance, support, and oversight to our CEO and management, helping us grow value responsibly. Their primary responsibilities include overseeing strategy, Board and CEO succession planning and remuneration, shareholder reporting, and approving major Company decisions.

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**.

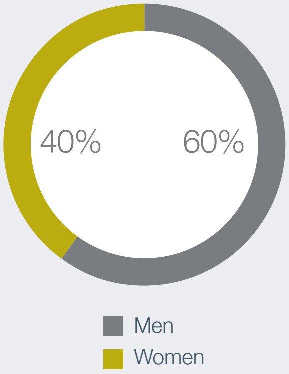
Board diversity

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.

As of December 31, 2024, our Board consisted of 10 independent directors along with our CEO. In 2024, Capital Power announced the appointment of Neil H. Smith and George Williams, following the retirement of Doyle Beneby from the Board.

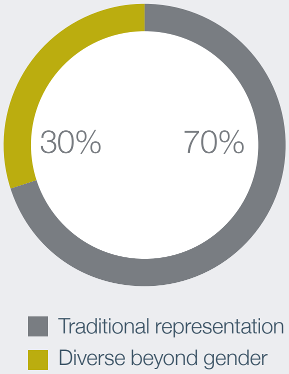
Board of Directors gender diversity[1]

As of December 31, 2024



Board of Directors diversity beyond gender[1]

As of December 31, 2024



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[1] Includes independent directors only.

Governance and risk management

Board of Directors[1]

New to the Board in 2024, we welcomed Neil H. Smith and George Williams. Neil H. Smith is the former Chief Executive Officer of Vanguard Renewables and InterGen. Neil has over 30 years of leadership expertise in the energy sector and deep experience in developing, building, and operating independent power generation infrastructure. George Williams is the former Chair and Chief Executive Officer of PMI Energy Solutions. George has over 40 years in the utility industry and hands-on operations experience from executive and senior leadership roles, in addition to nuclear energy experience from prior positions.

Left to right:

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

> “On behalf of the Board, I would like to extend a warm welcome to Neil and George. Both bring impressive power experience and expertise that will complement the Board’s skills as we expand in the U.S.”
>
> **Jill Gardiner,** Board Chair

Executive Team[1]

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 inspire Capital Power employees to work together to safely deliver, build, and create balanced energy solutions.

Left to right:

Jason Comandante
SVP, Head of Canada

Pauline McLean
SVP, External Relations and Chief Legal Officer

Steve Wollin
SVP, Operations

Avik Dey
President and Chief Executive Officer

Jacquie Pylypiuk
SVP, Technology and Chief People and Culture Officer

Sandra Haskins
SVP, Finance and Chief Financial Officer

May Wong
SVP, Energy Markets and Low Carbon Solutions

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[1] Board of Directors and Executive Team as of February 26, 2025.

Our approach to risk management

Risk management is everyone's responsibility, from the Board to individual employees. Together, our Code of Conduct and Enterprise Risk Management (ERM) program, combined with our robust corporate governance create the foundation for our risk management culture.

Code of Conduct

We launched our new Code of Conduct in 2024, designed to inform behaviour and help employees, contractors, agents and the Board avoid misconduct. By providing clear direction, tools and guidance, our Code of Conduct supports risk mitigation and protects the interests of Capital Power and our customers, shareholders, and other stakeholders.

Enterprise risk management

Our Company-wide ERM program is embedded in our strategic and long-term planning, operational planning and budgeting process, and all aspects of our operations. Our ERM program is based on the Committee of Sponsoring Organizations standard for risk management (COSO ERM – Integrated Framework) and is governed by our ERM Policy.

Risk management framework

Risk governance and oversight

Board

- The Board reviews Capital Power's risk register quarterly.
- The Board reviews and approves the Company's risk appetite and tolerances and ERM Policy.

Risk management and oversight

- The President and CEO has ultimate accountability for identifying and managing the Company's risks and approves the ERM framework.

Risk management process

Quarterly risk review →	Risk register is updated →	Executive and Board review →	Company-wide employee awareness
We assess Company risks on a quarterly basis, following interviews with Executive risk owners and their delegates to identify new or changing risks. Risks are evaluated using quantitative and qualitative methods to determine their severity and prioritize and design appropriate responses.	Individual risk assessments are consolidated and scored within the risk register in order to show changes to Capital Power's exposure quarterly along with corresponding mitigating controls that allow risks to be monitored.	The Executive and Board receive a consolidated risk report with updates on changes in the risk profile and emerging risks being monitored. Results are also shared with the Internal Audit team to be used in the annual risk-based internal audit plan, which provides the Board and Management independent assurance that key risks are being managed effectively.	To ensure risk is understood and managed effectively, we make risk management a central part of our operations by embedding the results into systems and procedures and providing regular updates to our management teams.

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.

Strategic growth risk

Our growth strategy involves identifying and executing on acquisition, development, and investment opportunities. This requires appropriate evaluation of opportunities, access to capital, and adequate resources to complete integration. If we are unable to successfully execute our growth strategy, we may not achieve our expected returns.

Key drivers	Key mitigations	2025 focus	Climate risk[1]
▸ Inadequate processes/resources/skillset to identify opportunities and integrate acquisitions ▸ Operational disruptions ▸ Inadequate evaluation of opportunities ▸ Changing political and regulatory landscapes ▸ Changing market fundamentals ▸ Commodity price volatility ▸ Uncompetitive cost of capital	▸ Strong governance framework and policy ▸ Lessons learned from post-implementation reviews to build on past experiences ▸ Regular review of internal hurdle rates ▸ Annual review of returns on investments and our strategy ▸ Highly skilled in-house commercial and operational expertise ▸ Data centre opportunity screening criteria ▸ Ability to access low-cost capital with our investment-grade credit rating	▸ Completion of integration of systems and processes at La Paloma ▸ Deliver on existing development commitments scheduled to commission in 2025 ▸ Preparation of flexible generation assets for data centre colocation opportunities	▸ Transition ▸ Physical

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[1] For further details on how we consider climate-related risks, refer to our TCFD disclosure.

Governance and risk management

Political and regulatory uncertainties

Unanticipated changes in political conditions and the regulatory environment in the jurisdictions in which we operate can have financial, reputational, and operational impacts to our business.

Key drivers	Key mitigations	2025 focus	Climate risk[1]
▸ Government decarbonization commitments misaligned with affordability and reliability needs ▸ Changes in power market design ▸ Economic uncertainties ▸ Affordability and reliability implications ▸ Required investments, incentives, and carbon assurance mechanisms ▸ Changes in carbon policy	▸ Advocating and engaging with government, industry groups, Indigenous communities and other stakeholders on new and emerging policies ▸ Maintaining active relationships with all levels of government ▸ Technological and geographical diversification ▸ Monitoring the evolution of and participating in carbon markets to mitigate carbon exposure	▸ Continue to monitor and advocate on new and emerging policies in both Canada and the U.S. (see the Regulatory matters section of the Business report for more information)	▸ Transition

Market volatility and operational disruption

Exposures to volatility in power and natural gas prices are relevant to our merchant facilities, especially when combined with operational disruptions. Operational disruptions and curtailments are also risks to our contracted facilities, both potentially resulting in financial impacts to our business.

Key drivers	Key mitigations	2025 focus	Climate risk[1]
▸ Extreme weather patterns ▸ Consumer behaviours ▸ Competitor behaviours ▸ Supply availability ▸ Market structures ▸ Maintenance practices ▸ Availability of critical spare parts ▸ Environmental regulations ▸ Availability of skilled labor, specialized contractor services	▸ Hedging through physical and financial derivatives ▸ Long-term contracts ▸ Strong commodity risk governance ▸ Fuel-type and geographical diversification ▸ Relationships with key suppliers ▸ Long-term service agreements ▸ Inventory of strategic spare parts ▸ Comprehensive insurance programs	▸ Continue to monitor and execute on mitigations	▸ Transition ▸ Physical

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[1] For further details on how we consider climate-related risks, refer to our TCFD disclosure.

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.

Our people and culture

Our work towards Powering Change by Changing Power™ is propelled by our highly skilled, agile and engaged team committed to innovation and excellence. Ensuring our people are comfortable and confident in bringing their authentic selves to work is critical to our success as we power a balanced energy future.

Employee resource groups

In 2024, we launched our newest employee resource group, THRIVE, which focuses on the mental and physical health of our employees. Through events and outreach, it works to create a supportive environment for employees, reducing the stigma of discussing mental health, sharing experiences and accessing resources.

WE Lead[1], which champions the advancement and well-being of women at Capital Power, celebrated its second year. It hosted several workshops focused on overcoming self-doubt and developing an authentic leadership style, as well as discussion panels highlighting women in engineering and operations roles.

Increasing women in energy

Historically, the energy sector has been predominantly male. Today, we are working to change this, both through our electrical and millwright apprenticeship programs for women and our long-time sponsorship of **The Rosie Mentorship Program**, a free six-month program that matches women seeking career advancement with mentors to help them reach their goals.

Insight into our identity

Our backgrounds, cultures, and identities all contribute to the work we do each day. To better understand and advance diversity across the organization, employees can self-identify based on criteria, including ethnicity, gender, sexual orientation, and disability. This gives us deeper knowledge about our workforce and enables us to set meaningful goals for attracting new employees and developing our leaders.

> In 2024, our Executive Team was led by 50% ☑ women, marking an increase from 44% in 2023. In recognition of Capital Power's commitment to gender diversity on our Executive Team, we have been listed on ***Globe and Mail's Women Lead Here*** list for five consecutive years.

Organizational changes

In 2024, our Company performed a strategic organizational review to optimize the organization to scale and grow efficiently, align our workforce with strategic objectives, and position us for long-term success (see Significant events). The organizational review resulted in a voluntary departure program (VDP) and election by employees into the VDP contributed to reduced female gender diversity across our organization compared to 2023. We remain committed to improving diversity across all levels of the Company and building on our inclusive environment.

Gender diversity[1]

	2024		2023[2]	
Employee category	Women ☑	Men	Women	Men
Executive	50%	50%	44%	56%
Upper management	26%	74%	30%	70%
Professional	31%	69%	29%	71%
Support / front line	19%	81%	22%	78%

[1] See our sustainability appendix for information about our sustainability reporting boundaries and definitions of our assured sustainability performance indicators.

[2] In 2024, we updated our externally reported employee categories for gender diversity to better align with other internal reporting. Gender diversity data for 2023 has been revised to align with these categories to allow for year-over-year comparison.

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[1] WE (Women Empowered) Lead was formerly known as EmpowHER.

Health, safety, security, and environment

The health, safety, and security of our employees is paramount at Capital Power. So, too, is protecting the health of our planet.

Our proactive approach

Health, safety, security, and the environment (HSSE) are the responsibility of every employee. Each member of our team has the right to get home safe and in good health every day.

Our approach focuses on:

Our People

We provide leading subject matter expertise in the right place at the right time, promoting a dynamic HSSE culture of awareness and participation at all levels, and consistently expanding our industry collaboration and learning opportunities.

Our Processes

Our robust HSSE Management System provides a consistent, repeatable, and transparent approach to managing HSSE-related risks.

Our Technology

We leverage current systems and technology to improve the end-user experience and ensure we can provide accurate data to support analysis, reporting, and program development.

We invest in frequent HSSE training and education for all employees and contractors who work on our sites. This can include annual site safety days with full-day hands-on training in areas such as hand tool safety and high-angle rescue.

Measuring our performance

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

Achieved an HSE Performance Index of 1.06 **exceeding our target of 1.0.**

Total recordable injury frequency (TRIF) was 0.53[1] in 2024. ☑

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[1] See our sustainability appendix for information about our sustainability reporting boundaries and definitions of our assured sustainability performance indicators.

Emissions management

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

We executed on our strategy in 2024 by acquiring strategically located grid-critical natural gas facilities to deliver reliable and affordable power. 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 future reporting.

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.

Scope 1

The charts on this page illustrate Scope 1 emissions across our fleet on an absolute and intensity basis. 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.

We have revised Scope 1 absolute emissions and intensity for 2021 through 2023 to depict facility acquisitions of Frederickson 1, La Paloma, and Harquahala.

Scope 1 emissions in 2024 were 17.4 $MtCO_2e$ ☑ representing a decrease from our 2023 revised emissions. Emissions reductions were largely driven by transitioning off coal at our Genesee Generating Station, which was completed midway through the year, as well as ceasing operation of the Genesee Mine. Decreased generation at our Clover Bar Energy Centre and Frederickson 1 facilities also contributed to our year-over-year reduction of absolute emissions.

GHG intensity in 2024 was 0.41 tonnes CO_2e/MWh ☑. The decrease in emissions intensity compared to 2023 is largely the result of transitioning off coal at our Genesee Generating Station.

Scope 2

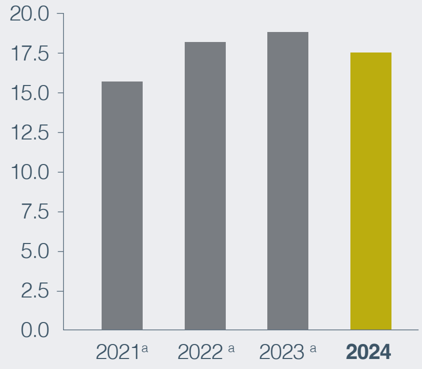
Location-based Scope 2 emissions for 2024 were 0.04 $MtCO_2e$. Our Scope 2 emissions have increased compared to 2023 as a result of increased grid-power consumed at our Genesee Generating Station, as well as additional power consumption associated with our newly acquired U.S. facilities.

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

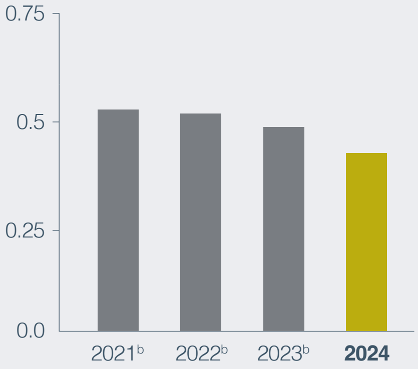
Scope 3

Scope 3 emissions in 2024 totalled 4.04 $MtCO_2e$, representing an increase year over year. The majority of our Scope 3 emissions are associated with upstream fuel- and energy-related activities, as well as purchased goods and services.

GHG emissions – Scope 1 absolute ($MtCO_2e$)



GHG Scope 1 emission intensity (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.

Community and stakeholder engagement

Our goal on every project is to build and operate power generation facilities in a way that aligns with the interests and priorities of the community and to preserve, nurture, and strengthen relationships with new and existing community members. Our approach is founded on respect, transparency, and developing enduring relationships that recognize the unique circumstances of individual communities and stakeholder groups.

Our engagement with communities is ongoing. It begins long before construction commences and does not end until after a site's decommissioning and reclamation. We work to connect with stakeholders in multiple ways and provide various options for them to engage with us, including personal conversations, toll-free phone lines, email channels, open houses, project newsletters, and community events.

In 2024, our Halkirk 2 Wind project was in full construction. We sent regular email project updates to residents and landowners in the project area throughout construction to share information and keep them informed on progress. Haul routes and schedules for major component deliveries and concrete pours were communicated daily. We had a manager onsite to liaise, address concerns and meet with residents and landowners.

Capital Power recognizes a busy construction period can sometimes be disruptive and inconvenient for residents. In August 2024, in thanks and appreciation, Capital Power hosted the community at the annual Halkirk Bullarama to support and enjoy the rodeo and share a meal together. Wrapping up the year and building on success from the previous year, we hosted an informal holiday dinner in the community for participating landowners. The event is an opportunity to mingle, share information and address any questions or concerns.

We are committed to meaningful, active engagement in the communities where we live and work. We seek to understand community priorities, build relationships and deliver collaborative solutions.

Community investment

Through ongoing engagement, we seek to understand community priorities, build relationships, and create positive, lasting impacts.

Based on input from community members and our employees, we focus our community investment in three areas:

- **Climate action:** Leading action, education, and the implementation of technologies and practices that will strengthen the long-term resiliency of communities in the face of climate change.
- **Equity and opportunity:** Increasing equity, access, and opportunity for all and creating safe, welcoming, and diverse spaces.
- **Wellbeing:** Building healthy communities where everyone can thrive.

In 2024, Capital Power contributed $3.7 million to community organizations, with our employees donating more than $680,000 through our employee matched-giving programs. Our matched-giving programs provide employees grants for volunteer hours, paid volunteer time, and an unlimited year-round match to registered charities in North America. Find out more about our community investment on our **website**.

Through our Community Sustainability Fund (CSF), we help to empower the communities where we live and work to achieve their climate and environmental action goals through grants of up to $20,000. In the CSF's first two years, we provided over $609,000 in funding to 37 organizations across North America.

Goodwill Industries of Alberta received a $20,000 grant in the CSF's inaugural year for their Repurpose by GW program. This program is staffed by Calgarians with disabilities, who transform unsold denim from Goodwill stores into reusable bags for purchase, diverting textiles from landfills. With this support, in 2024, they were able to purchase sewing machines, equipment, and supplies and fund training and salaries for those creating the bags.

Support for our neighbours

Supporting youth in our communities

In Phoenix, where we opened our U.S. regional headquarters in 2024, we partnered with the Homeless Youth Connection (HYC) to help eliminate barriers to high school graduation for youth experiencing homelessness. Through a $50,000 matched donation campaign, we helped raise over $82,000 to support HYC's work. Capital Power employees in Phoenix also volunteered their time to help pack 200 hygiene kits for those served by HYC.

Indigenous communities and engagement

Capital Power is committed to reconciliation with Indigenous Peoples and recognizes the energy expansion must be in partnership with Indigenous Peoples of North America.

We proudly work with Indigenous communities in Canada and the U.S. in the development, construction and operation of our projects. We believe in demonstrating action, following through on commitments, and consistency of engagement, understanding it is integral to building and maintaining strong relationships.

Partnering with the Maskwacis First Nations

In 2024, we entered into a three-year partnership and equity option agreement for our Halkirk 2 Wind project with the Louis Bull Tribe, Ermineskin Cree Nation, Montana First Nation and Samson Cree Nation of Maskwacis in Alberta (see Significant events). Following the three-year participation agreement, we are offering the four First Nations an opportunity to acquire a combined total of 25% of Halkirk 2 Wind, resulting in an ownership stake in our renewable energy facility. As part of our commitment to reconciliation, the agreement provides an equitable profit-sharing model that supports a pathway for future, long-term equity ownership in the project.

Transforming our commitment into action

In 2024, we introduced our ReconciliAction Plan and launched our inaugural cross-functional ReconciliAction Steering Committee. The Committee will apply an Indigenous lens across our business processes and practices with a focus on three priorities:

- Internal growth and awareness
- Relationship building and community support
- Capacity building and economic opportunities

In 2024, we progressed our participation in reconciliation by:

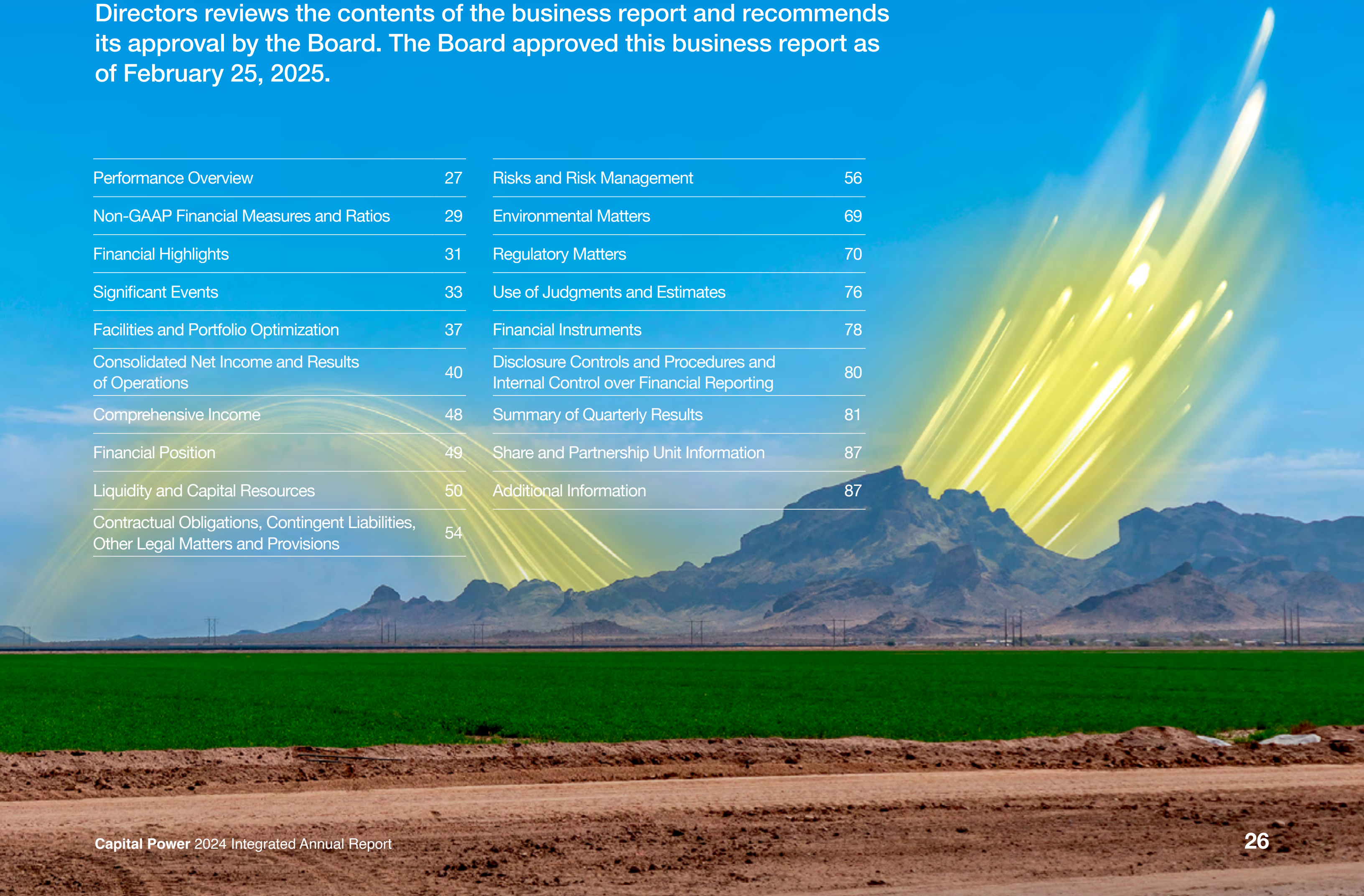
- Building and maintaining a directory of Indigenous-owned, -led or -affiliated organizations to improve Capital Power's procurement processes, support Indigenous businesses and diversify the Company's supply chain.
- Providing internal cultural awareness training to all employees.
- Sharing Indigenous cultural articles with employees quarterly and recognizing significant Indigenous days including National Indigenous Peoples Day and National Day for Truth and Reconciliation.
- Attending Indigenous conferences such as the National Coalition of Chiefs Clean Energy Summit, Forward Summit East and West, and the First Nations Major Project Coalition Conference.
- Donating 7% of our Community Investment budget to Indigenous organizations and initiatives.
- Deepening our relationships with Indigenous communities by participating in 20 community events that connected us with Indigenous community priorities and cultural values.
- Offering over 15 scholarships to Indigenous youth and students in British Columbia, Alberta, and Ontario.
- Partnering with Bears' Lair to bring Indigenous Youth Entrepreneur Dream camps to local Indigenous communities to foster the spirit of Indigenous business across Canada.

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

Business Report

This business report, prepared as of February 25, 2025, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and our subsidiaries for the years ended December 31, 2024 and December 31, 2023, the annual information form of Capital Power Corporation for the year ended December 31, 2024 and the remainder of the 2024 IAR, including both the sections preceding this business report and the cautionary statements regarding forward-looking information in the section following this business report.

In this business report, financial information for the years ended December 31, 2024, 2023 and 2022 is based on the audited consolidated financial statements of Capital Power which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of our Board of Directors reviews the contents of the business report and recommends its approval by the Board. The Board approved this business report as of February 25, 2025.



Performance overview

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

Operational priorities and performance targets for Capital Power in 2024 include a balanced approach to the energy transition in our markets:

Priority	2024 target	Status at December 31, 2024
Deliver		
Provide safe, reliable generation	Facility availability average of **93%** or greater	**92%**[1] **availability**
Execution of major turnarounds at seven facilities	Sustaining capital expenditures of **$180 million to $200 million**	**$199 million**[1,2]
Generate financial stability and strength	▸ Adjusted funds from operations[3] - 2024 target: **$770 million to $870 million**	**$817 million**[1]
	▸ Adjusted EBITDA[3] - Updated guidance[4] of **$1,310 million to $1,410 million** - Initial 2024 target: **$1,405 million to $1,505 million**	**$1,333 million**[1]
Portfolio optimization and integration	Successful integration of U.S. acquisitions and evaluation of business development opportunities	The acquisitions of La Paloma and Harquahala closed in February 2024 (see Significant events) with operational integration completed for Harquahala and on track for La Paloma to be operationally integrated in 2025.[5]
Build		
Complete $1.35 billion repower project and successful off-coal transition	Commission combined cycle for Genesee Units 1 and 2	The repower project achieved commercial operations during 2024. Costs to complete the project will continue into 2025 with a total expected cost of $1.55 billion to $1.65 billion, due to incremental costs and productivity challenges throughout the year (see Significant events).
Advance construction on over 560 MWs of incremental capacity	Continue construction on Ontario growth and commercial initiative projects, Halkirk 2 Wind, and Maple Leaf Solar on schedule	▸ Construction on the Ontario growth and commercial initiative projects is underway and remains on track to meet the anticipated in-service dates (see Capital expenditures and investments). ▸ Maple Leaf Solar is on track with updated anticipated in-service date in first quarter of 2027. ▸ Full commercial operations of Halkirk 2 Wind is expected in the first half of 2025 (revised from the fourth quarter of 2024) due to a site-wide stand-down resulting from a nacelle and rotor at one of the turbines falling from the tower in November 2024. In June 2024, the project received Alberta Utilities Commission (AUC) approval for 28 of 31 of the turbines originally planned for the project. Management is evaluating options for the remaining 3 turbines (see Capital expenditures and investments).
Expand U.S. renewables portfolio	Continue to explore opportunities to build or acquire renewable facilities in the U.S.	Successfully executed PPAs for the Hornet Solar and Bear Branch Solar projects in June 2024. Located in North Carolina, these projects have a total capacity of 107.5 MW. Hornet Solar began construction in August 2024, and construction of Bear Branch Solar is expected to commence in the first half of 2025 (see Significant events).

Performance overview

Priority	2024 target	Status at December 31, 2024
Create		
Advance lower-carbon solutions	Continue to explore economic viability of carbon capture and storage (CCS) in markets compatible with the technology	While the positive results from the FEED study affirmed the technology, we have deemed the Genesee CCS project uneconomic at this time and was discontinued (see Significant events). Capital Power will continue to evaluate CCS for viability at certain assets in our North American fleet.
	Evaluate SMRs in Alberta	Announced Partnership with Ontario Power Generation to assess new nuclear in Alberta. In 2024, Capital Power qualified for $13 million in Government of Canada funding to support certain activities to be undertaken as part of the feasibility assessment (see Significant events).

[1] For the year ended December 31, 2024.

[2] Net of partner contributions of $9 million and includes our share of joint venture sustaining capital expenditures of $46 million.

[3] Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures and as a result do not have standardized meanings. These measures may not be comparable to similar financial measures disclosed by other issuers. See Non-GAAP Financial Measures and Ratios.

[4] In the second quarter of 2024, the adjusted EBITDA guidance range was revised and remained unchanged for the rest of the year.

[5] Full integration includes operations and people. Operational integration involves systems, processes, and technology while people integration includes onboarding the workforce as Capital Power employees, organizational alignment and alignment of management practices.

Non-GAAP financial measures and ratios

Capital Power uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from our joint venture interests, gains or losses on disposals and other transactions and 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 (adjusted EBITDA), and (ii) adjusted funds from operations (AFFO) as specified financial measures. Adjusted EBITDA and AFFO are both non-GAAP financial measures.

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

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

Adjusted EBITDA

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

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

	Year ended December 31		Three months ended							
($ millions)	**2024**	2023	**Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	Dec 2023	Sep 2023	Jun 2023	Mar 2023
Revenues and other income	**3,776**	4,282	**853**	**1,030**	**774**	**1,119**	984	1,150	881	1,267
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	**(2,451)**	(2,657)	**(658)**	**(612)**	**(504)**	**(677)**	(694)	(626)	(614)	(723)
Remove unrealized changes in fair value of commodity derivatives and emission credits	**(238)**	(321)	**48**	**(78)**	**(8)**	**(200)**	(14)	(151)	23	(179)
Remove other non-recurring items[1]	**47**	5	**43**	**–**	**4**	**–**	1	4	–	–
Adjusted EBITDA from joint ventures[2]	**199**	146	**44**	**61**	**57**	**37**	36	37	37	36
Adjusted EBITDA	**1,333**	1,455	**330**	**401**	**323**	**279**	313	414	327	401
Depreciation and amortization	**(503)**	(574)	**(137)**	**(124)**	**(120)**	**(122)**	(142)	(148)	(143)	(141)
Unrealized changes in fair value of commodity derivatives and emission credits	**238**	321	**(48)**	**78**	**8**	**200**	14	151	(23)	179
Other non-recurring items[1]	**(47)**	(5)	**(43)**	**–**	**(4)**	**–**	(1)	(4)	–	–
Impairment	**(27)**	–	**–**	**(27)**	**–**	**–**	–	–	–	–
Foreign exchange (losses) gains	**(29)**	(6)	**(20)**	**5**	**(4)**	**(10)**	(2)	(9)	4	1
Net finance expense	**(221)**	(166)	**(61)**	**(65)**	**(53)**	**(42)**	(49)	(35)	(34)	(48)
Gain on divestiture	**309**	–	**309**	**–**	**–**	**–**	–	–	–	–
(Losses) gains on disposals and other transactions	**(31)**	(3)	**(11)**	**(5)**	**(17)**	**2**	(5)	5	(3)	–
Other items[2,3]	**(123)**	(81)	**(32)**	**(32)**	**(34)**	**(25)**	(22)	(19)	(19)	(21)
Income tax expense	**(198)**	(204)	**(45)**	**(53)**	**(23)**	**(77)**	(11)	(83)	(24)	(86)
Net income	**701**	737	**242**	**178**	**76**	**205**	95	272	85	285
Net income attributable to:										
Non-controlling interests	**2**	(7)	**2**	**(1)**	**1**	**–**	(2)	(2)	(2)	(1)
Shareholders of the Company	**699**	744	**240**	**179**	**75**	**205**	97	274	87	286
Net income	**701**	737	**242**	**178**	**76**	**205**	95	272	85	285

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

For the year ended December 31, 2023, other non-recurring items reflects restructuring costs of $3 million and costs related to the end-of-life of Genesee coal operations of $2 million. For the three months ended December 31, 2023, this reflects costs related to the end-of-life of Genesee coal operations of $1 million.

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

3 Includes finance expense, depreciation expense and unrealized changes in fair value of derivative instruments from joint ventures.

Non-GAAP financial measures and ratios

Adjusted funds from operations and adjusted funds from operations 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.

AFFO represents net cash flows from operating activities adjusted to:

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

	Year ended December 31		Three months ended December 31	
($ millions)	**2024**	2023	**2024**	2023
Net cash flows from (used in) operating activities per consolidated statements of cash flows	**1,144**	822	**438**	(18)
Add (deduct) items included in calculation of net cash flows from (used in) operating activities per consolidated statements of cash flows:				
Interest paid	**163**	111	**31**	8
Realized gains on settlement of hedged interest rate derivatives	**(42)**	(20)	**–**	(10)
Change in fair value of derivatives reflected as cash settlement	**(13)**	(249)	**4**	(38)
Distributions received from joint ventures	**(120)**	(36)	**(96)**	(11)
Miscellaneous financing charges (received) paid[1]	**(6)**	13	**–**	7
Income taxes paid	**38**	214	**21**	178
Change in non-cash operating working capital	**(173)**	226	**(166)**	100
	(153)	259	**(206)**	234
Net finance expense[2]	**(186)**	(134)	**(50)**	(37)
Current income tax expense	**(31)**	(155)	**(2)**	(20)
Sustaining capital expenditures[3]	**(152)**	(92)	**(56)**	(20)
Preferred share dividends paid	**(31)**	(32)	**(7)**	(9)
Cash received for off-coal compensation	**50**	50	**–**	–
Remove tax equity interests' respective shares of adjusted funds from operations	**(6)**	(7)	**(2)**	(2)
Adjusted funds from operations from joint ventures	**117**	92	**18**	22
Other non-recurring items[4]	**65**	16	**49**	12
Adjusted funds from operations	**817**	819	**182**	162
Weighted average number of common shares outstanding (millions)	**128.9**	117.1	**132.1**	117.4
Adjusted funds from operations per share ($)	**6.34**	6.99	**1.38**	1.38

[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.

[3] Includes sustaining capital expenditures net of: (i) partner contributions of $9 million and $1 million for the year and three months ended December 31, 2024, respectively, compared with $6 million and $1 million for the year and three months ended December 31, 2023, respectively and (ii) insurance recoveries of $1 million and $3 million for the year ended December 31, 2024 and 2023, respectively.

[4] For the year 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 $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.

For the year ended December 31, 2023, other non-recurring items reflects restructuring costs of $3 million, costs related to the end-of-life of Genesee coal operations of $8 million and dividend equivalent payments for the subscription receipt offering of $7 million, net of current income tax recovery of $2 million. For the three months ended December 31, 2023, other non-recurring items reflects costs related to the end-of-life of Genesee coal operations of $7 million and dividend equivalent payments for the subscription receipt offering of $7 million, net of current income tax recovery of $2 million.

Financial highlights

	Year ended December 31		
($ millions, except per share amounts)	**2024**	2023	2022
Revenues and other income	**3,776**	4,282	2,929
Adjusted EBITDA[1]	**1,333**	1,455	1,353
Net income	**701**	737	128
Net income attributable to shareholders of the Company	**699**	744	138
Basic earnings per share ($)	**5.16**	6.07	0.85
Diluted earnings per share ($)[2]	**5.15**	6.04	0.84
Net cash flows from operating activities	**1,144**	822	935
Adjusted funds from operations[1]	**817**	819	848
Adjusted funds from operations per share ($)[1]	**6.34**	6.99	7.28
Purchase of property, plant and equipment and other assets, net	**1,070**	723	682
Dividends per common share, declared ($)	**2.5338**	2.3900	2.2550
Dividends per Series 1 preferred share, declared ($)	**0.6553**	0.6553	0.6553
Dividends per Series 3 preferred share, declared ($)	**1.7151**	1.3633	1.3633
Dividends per Series 5 preferred share, declared ($)	**1.6577**	1.4836	1.3095
Dividends per Series 9 preferred share, declared ($)[3]	**N/A**	N/A	1.0781
Dividends per Series 11 preferred share, declared ($)[4]	**0.7188**	1.4375	1.4375

	At December 31		
	2024	2023	2022
Loans and borrowings including current portion	**4,976**	4,716	3,726
Total assets	**12,930**	11,156	10,135

1 The consolidated financial highlights, except for adjusted EBITDA, AFFO and AFFO per share were prepared in accordance with GAAP. See Non-GAAP financial measures and ratios.
2 Diluted earnings per share was calculated after giving effect to outstanding share purchase options.
3 On September 30, 2022, Capital Power redeemed all of our 6 million issued and outstanding 5.75% cumulative rate reset preference shares, Series 9.
4 On June 30, 2024, Capital Power redeemed all of our 6 million issued and outstanding 5.75% cumulative minimum rate reset preference shares, Series 11 (see Significant events).

Adjusted EBITDA for the year ended December 31, 2024, was lower than the corresponding period in 2023 largely due to lower generation and lower power prices captured by our Alberta commercial portfolio and full recognition of the off-coal compensation from the Province of Alberta at the end of 2023, partly offset by the following factors:

- lower emissions cost from reduced intensity driven by a shift to more natural gas versus coal as the Genesee Generating Station facilities are 100% natural gas-fueled as of June 18, 2024 (see Significant events),
- increased U.S. facility contributions from Frederickson 1 which was acquired in December 2023, and Harquahala and La Paloma acquired in February 2024, and
- strong U.S. trading results for the year due to increased trading activity and higher realized gains from our power and environmental trading portfolio.

Financial highlights

AFFO for the year ended December 31, 2024, was slightly lower than the corresponding period in 2023 primarily due to:

- lower adjusted EBITDA, higher finance expense attributable to increased loans and borrowings outstanding due to issuances in the second half of 2023 and 2024, and higher sustaining capital expenditures as a result of larger outage scope and recent acquisitions,
- partly offset by decreased current income tax expense due to lower overall consolidated net income before tax, higher tax deductions for certain capital projects.

Revenues and other income for the year ended December 31, 2024 were lower compared to the same period in 2023 primarily due to lower generation and lower power prices captured by our Alberta commercial portfolio and less favourable changes in the fair value of commodity derivatives and emission credits. This was partly offset by increased contributions from U.S. facilities Frederickson 1 and La Paloma, acquired in December 2023 and February 2024, respectively. Further contributing to the decline is lower revenues from cost recoveries and other income related to off-coal compensation from the Province of Alberta that was fully recognized at the end of fiscal 2023.

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

Basic and diluted earnings per share changes were driven by the same factors as net income, which are discussed in Consolidated Net Income and Results of Operations and the changes from period to period in the weighted average number of common shares outstanding.

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

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

Significant events

Renewable power asset sell-down

On December 20, 2024, the Company closed its sale of 49% interests in the Quality Wind facility in British Columbia and the Port Dover and Nanticoke Wind facility in Ontario to Axium Infrastructure. Total pre-tax cash proceeds from the transaction are $333 million, inclusive of working capital. At December 31, 2024, transaction fees of $7 million have been recorded within trade and other payables.

The two wind facilities are fully contracted with investment grade counterparties and have a remaining weighted average contract life of ~11 years. Capital Power will continue to manage and operate the assets on behalf of the newly formed partnership under a long-term asset management agreement. Consistent with its strategy, the transaction represents the crystallization of a levered equity return in excess of Capital Power's capital allocation thresholds and enhances its financial flexibility.

$460 million bought offering of common shares

On December 17, 2024, the Company completed a public offering of 7,820,000 common shares (inclusive of the full exercise of a 1,020,000 common shares over-allotment option), at an issue price of $58.80 per common share for total gross proceeds of approximately $460 million (the Offering) less issue costs of $19 million.

The Company intends to use the net proceeds from the Offering to fund future potential acquisitions and growth opportunities and for general corporate purposes.

Genesee is off coal and repowering achieves commercial operations

On June 18, 2024, the Company reached a significant milestone for the Genesee Repowering project with the announcement that the Genesee Generating Station is off coal and now 100% natural gas-fueled, resulting in the facility being off coal more than 5 years ahead of the Alberta government mandate.

On December 13, 2024, the Company announced that its Genesee Repowering project as Genesee Unit 2 achieved combined cycle commercial operations. This milestone marked a significant phase in the Genesee Repowering project, resulting in Genesee Units 1 and 2 becoming Canada's most efficient natural gas combined cycle facility.[1] The advancement of this project increases overall capacity at the Genesee Generating Station by 512 MW and reduces CO_2 emissions (Scope 1) by 3.4 Mt annually[2] – representing a ~60% increase in capacity while reducing emissions (Scope 1) by ~40%.

The approximately $1.5 billion project began construction in summer 2021 requiring more than 5.8 million hours of labour with a peak of ~1,250 workers on site. Located entirely within the footprint of the existing Genesee Generating Station, the project involved installing two new Mitsubishi M501JAC gas-fired combustion turbines and Vogt triple-pressure heat recovery steam generators, while utilizing the units' existing steam turbine generators.

The Genesee Generating Station is now capable of delivering up to 1,857 MW of reliable, affordable and lower-carbon power for Alberta's thriving economy. The significant baseload generation available on the 26,000+ acre site supports grid-wide reliability while presenting opportunities for future development, energizing the Alberta advantage for new technologies, industries and growth. With the project now complete, Capital Power will be referring to the Genesee Generating Station as a single facility in our portfolio (30 total facilities instead of 32 when counting all three units separately).

Refinancing of York Energy

On November 27, 2024, York Energy successfully refinanced and upsized its existing term loan for an additional approximately ten-year term maturing April 30, 2035. The $315 million term loan bears interest at a fixed rate of 5.34% and is repayable in quarterly installments. This refinancing creates interest savings of approximately 0.66% and extends the maturity to align with the PPA expiring in 2035.

Organizational review – voluntary departure program

On October 24, 2024, the Company announced the rollout of the VDP and achieved a reduction in its Canada-based corporate employees of approximately 40% (165 positions). The VDP is the result of 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 a total cost of $49 million, which includes $10 million related to employee benefit costs that would have otherwise been incurred in future periods. The total restructuring costs are expected to be paid within the next six months as the employees participating in the VDP will depart the Company by June 2025.

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[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 efficient combined cycle units currently operating in Canada.

[2] Anticipated GHG emission reductions from Genesee Repowering project and transition off-coal compared to 2019 facility emissions.

Significant events

$600 million medium-term notes offering

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). The Notes have a coupon rate of 4.831% and mature on September 16, 2031. The Company used the net proceeds to repay, redeem and refinance existing indebtedness, including indebtedness under the Company's credit facilities, and for general corporate purposes.

$350 million subordinated notes, Series 1 exchange

On August 15, 2024, the Company announced the approval of amendments to the indenture governing the $350 million 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 1, due September 9, 2082 (Series 1 Notes). These changes allowed for the exchange of all outstanding principal amount of Series 1 Notes for an equal principal amount of new 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 3, due September 9, 2082 (Series 3 Notes).

The Series 3 Notes have the same economic terms as the Series 1 Notes, including interest rates and maturity dates, but without the provision for delivery of preferred shares upon the occurrence of certain bankruptcy and related events. Holders will continue to receive interest accrued on the exchanged Series 1 Notes.

This note exchange was completed on August 15, 2024, following the execution of the necessary supplemental indentures. The Series 3 Notes will rank equally in right of payment with the $450 million 8.125% Fixed-to-Fixed Subordinated Notes, Series 2, due June 5, 2054. S&P Global Ratings and Morningstar DBRS confirmed the instrument rating of the Series 3 Notes at BB and BB with a Stable trend, respectively.

Dividend increase

On July 30, 2024, the Board approved an increase of 6% in the annual dividend for holders of its common shares, from $2.46 per common share to $2.61 per common share. This increased common share dividend commenced with the third quarter 2024 quarterly dividend payment on October 31, 2024 to shareholders of record at the close of business on September 30, 2024.

Partnership with Maskwacis First Nations

On July 19, 2024, the Company signed a three-year partnership and equity option agreement with the Louis Bull Tribe, Ermineskin Cree Nation, Montana First Nation and Samson Cree Nation of Maskwacis located in Alberta. Following the three-year agreement, the Company is offering the four First Nations an opportunity to acquire a combined total of 25% of Halkirk 2 Wind. As part of the Company's commitment to reconciliation, the agreement provides an equitable profit-sharing model that supports a pathway to future, long-term equity ownership in the project that can support these nations with sustainable income throughout the lifetime of its operations.

Executes 25-year contracts for Hornet Solar and Bear Branch Solar projects in North Carolina

In June 2024, the Company successfully executed 25-year power purchase agreements with Duke Energy Carolinas for the Hornet Solar and Bear Branch Solar projects located in North Carolina totalling 107.5 MW. Hornet Solar began construction in August 2024 and Bear Branch is expected to commence construction in the first half of 2025. Targeted commercial operations for both projects is expected in the second half of 2026.

$450 million subordinated notes offering

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

The Company used the net proceeds from the sale of the Subordinated Notes to repay certain amounts drawn on the Company's credit facilities (which include amounts drawn for the acquisition of a 50% interest in New Harquahala Generating Company, LLC, and a 100% interest in CXA La Paloma, LLC, and related expenses, development purposes and in respect of ongoing operations), to redeem all of the Company's outstanding Cumulative Minimum Rate Reset Preference Shares, Series 11 (TSX: CPX.PR.K), (the Preferred Shares, Series 11) and for general corporate purposes.

Redemption of Preferred Shares, Series 11

On June 30, 2024, the Company redeemed all of its 6 million issued and outstanding Preferred Shares, Series 11 at a price of $25.00 per share (Redemption Price) for an aggregate total of $150 million, less any tax required to be deducted and withheld by the Company.

Significant events

Board of Director changes

On May 15, 2024, the Company announced the appointment of Neil H. Smith and George Williams to the Board effective May 15, 2024. The appointments follow Doyle Beneby's retirement, after serving the full 12-year term limit as a member of the Board. With these appointments and retirement, the Board consists of 11 directors, with 40% of the independent directors being women, and 30% of the independent directors representing diverse groups beyond gender.

Discontinuation of $2.4 billion Genesee CCS project

Capital Power is discontinuing pursuit of the Genesee CCS project. Through our development of the project, we have confirmed that CCS is a technically viable technology and potential pathway to decarbonization for thermal generation facilities including Genesee Generating Station. However, at this time, the project is not economically feasible and as a result we will be turning our time, attention, and resources to other opportunities to serve our customers with balanced energy solutions. As part of our discontinuation of the project, Capital Power incurred a pre-tax cost of $18 million, related to termination of sequestration hub evaluation work. Capital Power looks forward to exploring CCS at Genesee Generating Station and certain assets in our North American fleet in the future as economics improve.

Large-scale virtual power purchase agreement with Saputo Inc.

On March 27, 2024, the Company announced it had entered into a 15-year virtual power purchase agreement (VPPA) with Saputo Inc. The agreement pertains to the Company's Canadian-based Halkirk 2 Wind facility currently under construction. Final regulatory approval was received in June 2024 and once operational, the portion of the wind facility contracted by Saputo will generate approximately 181,000 MWh of renewable electricity per year (see Performance Overview).

Acquisitions of CXA La Paloma, LLC and New Harquahala Generating Company, LLC

The La Paloma Acquisition and the Harquahala Acquisition closed on February 9, 2024 and February 16, 2024, respectively.

The Company entered into two separate definitive agreements with CSG Investments, Inc., a subsidiary of Beal Financial Corporation, to acquire:

- 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 La Paloma Acquisition); and
- under a newly formed 50/50 partnership between Capital Power Investments, LLC and an affiliate of a fund managed by BlackRock's Diversified Infrastructure business (BlackRock), 100% of the equity interests in New Harquahala Generating Company, LLC (Harquahala), which owns the 1,092 MW Harquahala natural gas-fired generation facility in Maricopa County, Arizona (the Harquahala Acquisition and together with the La Paloma Acquisition, the Acquisitions).

Under the newly established 50/50 partnership, Capital Power and BlackRock were each responsible for funding 50% of the cash consideration for the Harquahala Acquisition. Capital Power is responsible for the operations and maintenance and asset management for which it will receive an annual management fee.

La Paloma and Harquahala are critical infrastructure assets, which support the reliability of California and Arizona's electricity grids and add further growth opportunities in the attractive Western Electricity Coordinating Council (WECC) market while balancing the Company's geographical footprint across North America. La Paloma is contracted under various resource adequacy contracts through 2029 with multiple investment grade utilities and load serving entities. Harquahala is 100% contracted under a tolling agreement through 2031 with an investment grade utility.

The Acquisitions are expected to generate average annual Adjusted EBITDA of approximately $265 million (US$197 million) for the 2024-2028 period and are estimated to be, on average, 8% accretive to AFFO per share over the same period.

The purchase price of the Acquisitions attributable to Capital Power was $1.5 billion (US$1.1 billion), subject to working capital and other customary closing adjustments. The Acquisitions were partially funded by a $400 million subscription receipt offering and $850 million medium-term notes offering in December 2023.

Significant events

Partnered with Ontario Power Generation to advance new nuclear in Alberta

On January 15, 2024, the Company announced that it had entered into an agreement with Ontario Power Generation (OPG) to jointly assess the development and deployment of grid-scale SMRs to provide lower-carbon, reliable nuclear energy for Alberta.

Pursuant to the agreement, the two companies will examine the feasibility of developing SMRs in Alberta, including possible ownership and operating structures. SMRs are being pursued by jurisdictions in Canada and around the world to power the growing demand for lower-carbon electricity and energy security.

Capital Power and OPG will complete the feasibility assessment within two years, while continuing to work on the next stages of SMR development. In the fourth quarter of 2024, Capital Power qualified for $13 million in funding to support certain activities to be undertaken as part of the feasibility assessment.

Facilities and portfolio optimization

Facility category and facility	Type of generating facility	Year commissioned	Net generating capacity (MW) Facility	Net generating capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Alberta commercial facilities						
Genesee Generating Station[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	Natural gas-fired simple cycle	2008 (Unit 1) 2009 (Units 2 and 3)	243	243	Merchant	–
Joffre	Natural gas-fired combined cycle cogeneration	2001	480	192	Merchant (mid-merit)	–
Shepard	Natural gas-fired combined cycle	2015	881	440	Merchant with tolling agreement for 50% of owned capacity	2035 (tolling agreement)
Halkirk 1 Wind	Wind turbine	2012	150	150	Merchant with RECs sold under fixed price agreement	2032 (RECs)
Clover Bar Landfill Gas	Landfill gas-fired	2005	2	2	Merchant with emission credits purchased by Capital Power from the City of Edmonton	–
Western Canada facilities						
Island Generation	Natural gas-fired combined cycle	2002	275	275	Electricity purchase agreement (EPA)[5] with BC Hydro	2026
Quality Wind[2]	Wind turbine	2012	142	72	EPA[5] with BC Hydro	2037
Savona[3]	Waste heat	2008	5	5	EPA[5] with BC Hydro	2028
150 Mile House[3]	Waste heat	2008	5	5	EPA[5] with BC Hydro	2028
Whitla Wind[4]	Wind turbine	2019 (Phase 1) 2021 (Phases 2 and 3)	353	353	Fixed price contract with the Alberta Electric System Operator for 202 MW	2039
					PPA[5] with Dow Chemical Canada ULC for 25 MW	2036
					VPPA[5] with ME Global Canada ULC for 126 MW	2032
Strathmore Solar	Solar	2022	41	41	PPA[5] with Telus Corporation covering energy and RECs	2047
Clydesdale Solar	Solar	2022	75	75	VPPA[5] with Labatt Breweries of Canada covering 38 MW of energy and RECs	2037
					VPPA[5] with Shaw Communications covering 30 MW of energy and RECs	2037
Ontario facilities						
York Energy	Natural gas-fired simple cycle	2012	456	228	Energy supply contract with IESO	2035
East Windsor	Natural gas-fired cogeneration	2009	92	92	Energy supply contract with IESO	2040
Goreway	Natural gas-fired combined cycle	2009	875	875	Energy supply contract with IESO	2035
Kingsbridge 1	Wind turbine	2001 and 2006	39	39	Energy supply contracts with IESO	2026
Port Dover and Nanticoke Wind[2]	Wind turbine	2013	105	54	Energy supply contract with IESO	2033

Facilities and portfolio optimization

			Net generating capacity (MW)			
Facility category and facility	**Type of generating facility**	**Year commissioned**	**Facility**	**Capital Power interest**	**Revenues based on**	**Contract expiry**
U.S. facilities						
Decatur Energy, Alabama	Natural gas-fired combined cycle	2002	885	885	Tolling agreement with Tennessee Valley Authority	2032
Arlington Valley, Arizona	Natural gas-fired combined cycle	2002	600	600	Tolling agreement with Arizona Public Service Company and Heat Rate Call Option (HRCO) with an investment grade counterparty	2031
Beaufort Solar, North Carolina	Solar	2015	15	15	PPA[5] with Duke Energy Progress, LLC	2030
Bloom Wind, Kansas	Wind turbine	2017	178	178	Fixed price contract with Allianz Risk Transfer	2027
Macho Springs Wind, New Mexico	Wind turbine	2011	50	50	PPA[5] with Tucson Electric Power	2031
New Frontier Wind, North Dakota	Wind turbine	2018	99	99	Fixed price contract with Morgan Stanley Capital Group	2030
Cardinal Point Wind, Illinois	Wind turbine	2020	150	150	Fixed price contract with Morgan Stanley Capital Group	2032
Buckthorn Wind, Texas	Wind turbine	2018	101	101	Offtake arrangements with an investment grade U.S. financial institution	2031 and 2038
Midland Cogeneration, Michigan	Natural gas-fired combine cycle	1990	1,633	817	PPA[5] with Consumers Energy Steam and EPA[5] with Dow Silicones and Corteva Agriscience	2030 and 2035
Frederickson 1, Washington	Natural gas-fired combine cycle	2002	265	133	Tolling agreement with Morgan Stanley Capital Group and Puget Sound Energy	2025 and 2030
La Paloma, California[6]	Natural gas-fired combined cycle	2003	1,062	1,062	Resource adequacy contracts with multiple investment grade utilities and load serving entities	2029
Harquahala, Arizona[6]	Natural gas-fired combined cycle	2004	1,092	546	Tolling agreement with an investment grade utility	2031

[1] For operational reporting, Genesee 1, 2 and 3 are combined as a single facility referred to as Genesee Generating Station (see Significant events). 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 Most Severe Single Contingency (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 (see Significant events).

[3] For operational reporting, Savona and 150 Mile House waste heat facilities are combined together as a single entity referred to as EnPower.

[4] For operational reporting, all phases of the Whitla Wind project are combined as a single facility referred to as Whitla Wind.

[5] Certain of our facilities derive revenues under power purchase agreements or arrangements (PPAs), VPPAs and energy purchase agreements or arrangements (EPAs).

[6] La Paloma and Harquahala were acquired in February 2024 (see Significant events).

Facilities and portfolio optimization

Facility category and facility	Type of generating facility	Year to be commissioned	Net generating capacity (MW) Facility	Net generating capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Under construction or in advanced development						
Halkirk 2 Wind, Alberta	Wind	2025	126	126	Clean electricity supply agreement with Public Services and Procurement Canada for 49% of energy	2045
					Renewable power purchase agreement with Saputo Inc. for 45% of energy	2040
Maple Leaf Solar	Solar	2027	73	73	PPA with Duke Energy Progress, LLC	2051
Hornet Solar[1]	Solar	2026	73	73	PPA with Duke Energy Carolinas	2051
Bear Branch Solar[1]	Solar	2026	35	35	PPA with Duke Energy Carolinas	2051
East Windsor Expansion	Natural gas-fired simple cycle	2026	106	106	Energy supply contract with IESO	2040
York Energy BESS	Battery energy storage system	2025	120	120	Energy supply contract with IESO	2047
Goreway BESS	Battery energy storage system	2025	50	50	Energy supply contract with IESO	2047
Goreway upgrade	Natural gas-fired combined cycle	2025	40	40	Energy supply contract with IESO	2035
York Energy Upgrade	Natural gas-fired simple cycle	2025	38	19	Energy supply contract with IESO	2035

[1] Refer to Significant events for updates on these facilities.

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 commercial 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 Alberta 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 2024 compared with 2023 are presented below followed by further discussion of these items.

($ millions)		
Consolidated net income for the year ended December 31, 2023		**737**
Increase (decrease) in adjusted EBITDA:		
Alberta commercial facilities and portfolio optimization	(230)	
Western Canada facilities	(6)	
Ontario facilities	(3)	
U.S. facilities	287	
Corporate	(170)	(122)
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(83)
Increase in gain on divestiture		309
Increase in losses on disposals and other transactions		(28)
Decrease in depreciation and amortization expense		71
Increase in impairment		(27)
Increase in foreign exchange loss		(23)
Increase in finance expense and depreciation from joint ventures		(42)
Increase in net finance expense		(55)
Changes in other non-recurring items		(42)
Decrease in income before tax		(42)
Decrease in income tax expense		6
Decrease in net income		**(36)**
Consolidated net income for the year ended December 31, 2024		**701**

Consolidated net income and results of operations

Results by facility category and other

	Year ended December 31							
	2024	2023	**2024**	2023	**2024**	2023	**2024**	2023
	Electricity generation (GWh)[1]		**Facility availability** (%)[2]		**Revenues and other income** ($ millions)[3]		**Adjusted EBITDA** ($ millions)[3,4]	
Total electricity generation, average facility availability and facility revenues	**37,821**	32,487	**92**	95	**2,383**	2,987		
Alberta commercial facilities								
Genesee Generating Station[5]	**8,559**	10,558	**87**	97	**569**	1,416		
Clover Bar Energy Centre	**638**	737	**74**	74	**74**	140		
Joffre	**658**	552	**93**	89	**70**	110		
Shepard	**2,938**	3,005	**93**	96	**161**	268		
Halkirk 1 Wind	**411**	453	**95**	95	**37**	62		
Clover Bar Landfill Gas	**–**	6	**–**	45	**–**	1		
Alberta commercial facilities	**13,204**	15,311	**88**	93	**911**	1,997		
Portfolio optimization	**N/A**	N/A	**N/A**	N/A	**975**	574		
	13,204	15,311	**88**	93	**1,886**	2,571	**550**	780
Western Canada facilities								
Island Generation	**334**	2	**100**	100	**11**	13		
Quality Wind[6]	**364**	386	**95**	96	**52**	54		
EnPower	**18**	16	**90**	87	**2**	2		
Whitla Wind	**1,268**	1,231	**96**	95	**62**	66		
Strathmore Solar	**70**	71	**97**	95	**4**	5		
Clydesdale Solar	**155**	145	**97**	95	**12**	12		
Halkirk 2 Wind[7]	**2**	N/A	**100**	N/A	**–**	N/A		
	2,211	1,851	**97**	97	**143**	152	**96**	102
Ontario facilities								
York Energy[6]	**42**	19	**99**	97	**N/A**	N/A		
East Windsor	**22**	12	**97**	98	**32**	32		
Goreway	**2,767**	2,318	**93**	96	**299**	295		
Kingsbridge 1	**91**	86	**94**	92	**8**	7		
Port Dover and Nanticoke Wind[6]	**256**	263	**95**	96	**39**	40		
	3,178	2,698	**94**	96	**378**	374	**237**	240

Consolidated net income and results of operations

	Year ended December 31							
	2024	2023	**2024**	2023	**2024**	2023	**2024**	2023
	Electricity generation (GWh)[1]		**Facility availability** (%)[2]		**Revenues and other income** ($ millions)[3]		**Adjusted EBITDA** ($ millions)[3,4]	
U.S. facilities								
Decatur Energy, Alabama	**3,589**	2,123	**95**	94	**111**	97		
Arlington Valley, Arizona	**3,566**	3,495	**94**	94	**182**	219		
Beaufort Solar, North Carolina	**25**	28	**97**	99	**2**	3		
Bloom Wind, Kansas	**669**	615	**94**	96	**40**	38		
Macho Springs Wind, New Mexico[8]	**130**	132	**96**	97	**16**	16		
New Frontier Wind, North Dakota	**380**	375	**90**	94	**22**	24		
Cardinal Point Wind, Illinois	**535**	544	**84**	93	**41**	42		
Buckthorn Wind, Texas	**350**	360	**96**	94	**25**	25		
Midland Cogeneration, Michigan[6]	**5,473**	4,955	**94**	95	**N/A**	N/A		
Frederickson 1, Washington[9]	**861**	N/A	**84**	N/A	**25**	N/A		
Harquahala, Arizona[6,9]	**1,658**	N/A	**81**	N/A	**N/A**	N/A		
La Paloma, California[9]	**1,992**	N/A	**95**	N/A	**387**	N/A		
U.S. trading	**N/A**	N/A	**N/A**	N/A	**52**	27		
	19,228	12,627	**92**	94	**903**	491	**656**	369
Corporate[10]					**19**	130	**(206)**	(36)
Unrealized changes in fair value of commodity derivatives and emission credits					**447**	564		
Consolidated revenues and other income and adjusted EBITDA					**3,776**	4,282	**1,333**	1,455

1 Gigawatt hours (GWh) of electricity generation reflects our share of facility output.

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

3 Commencing in 2024, as U.S. trading activity continued to grow, the Company reclassified the presentation of U.S. trading within Alberta portfolio optimization to the U.S. facilities category to better reflect the nature of these activities. Comparatives for revenues and other income and adjusted EBITDA were reclassified to conform to the current presentation.

4 The financial results by facility category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP financial measures and ratios.

5 Genesee repowered units 1 and 2 simple cycle commissioned May 3, 2024 and June 28, 2024, respectively and dual cycle commissioned November 18 and December 13, 2024, respectively. Genesee Units 1, 2 and 3 are now presented together as the Genesee Generating Station (see Significant events).

6 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 joint ventures on our consolidated statements of income. Capital Power's share of each facility's adjusted EBITDA is included in adjusted EBITDA above.

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

The equivalent of Capital Power's share of the equity method facilities' revenues and other income was $439 million for 2024, compared with $353 million for 2023. The facilities' revenues and other income are not included in the above results.

7 Halkirk 2 Wind commenced partial operations in the fourth quarter of 2024 with full commercial operations expected in the first half of 2025 (see Capital expenditures and investments).

8 For assets that are controlled by the Company, but have non-controlling interests, amounts in this table represent 100% of the amounts related to the respective assets.

9 Frederickson 1, Harquahala and La Paloma were acquired December 28, 2023, February 16, 2024 and February 9, 2024, respectively (see Significant events). Due to the proximity of Frederickson 1's acquisition to December 31, 2023, generation, availability, and revenues were immaterial.

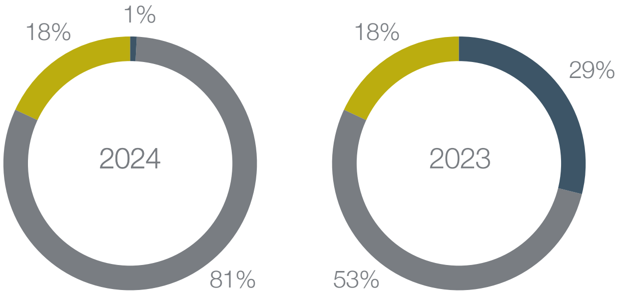
10 Corporate revenues were offset by interplant category eliminations.

Consolidated net income and results of operations

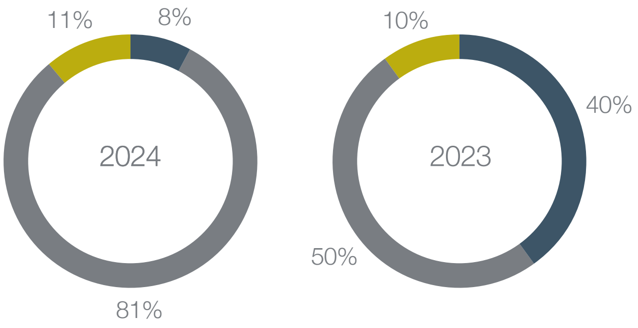
Adjusted EBITDA and revenues and other income by fuel type for the year ended December 31

Alberta commercial portfolio optimization amounts in adjusted EBITDA and revenues and other income are allocated to fuel source based on generation of baseload assets and off-coal compensation is reflected within natural gas / coal dual-fuel. Off-coal compensation was fully recognized during 2023 leading to lower contributions to natural gas / coal dual-fuel going forward. The increase in percentages from our flexible generation facilities is mainly due to reclassifying Genesee 3 (within Genesee Generating Station) to flexible generation after the conversion in May 2023, and repowering of Genesee units 1 and 2 in 2024 (see Significant events). Also contributing to the increase are the acquisitions of Frederickson 1 at the end of 2023, and La Paloma and Harquahala in the first quarter of 2024 (see Significant events). Contributions to revenue and adjusted EBITDA from renewable facilities have remained consistent.

Adjusted EBITDA[1] by fuel type



Revenues and other income by fuel type[2]



[1] See Non-GAAP Financial Measures and Ratios.

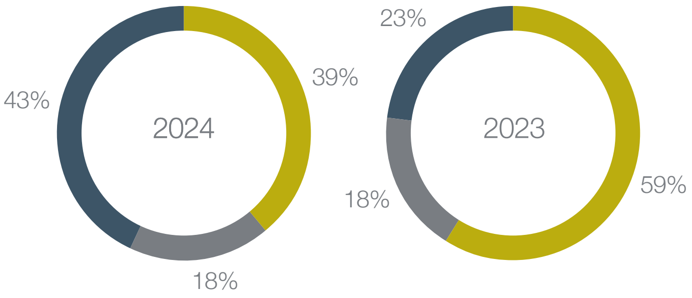
[2] The allocation of revenues and other income by fuel type excludes the impacts of unrealized changes in fair value of commodity derivatives and emission credits.

[3] Flexible generation is defined as the Company's natural gas generation assets and energy storage business. Comparative information has been reclassified to conform to the current year's presentation.

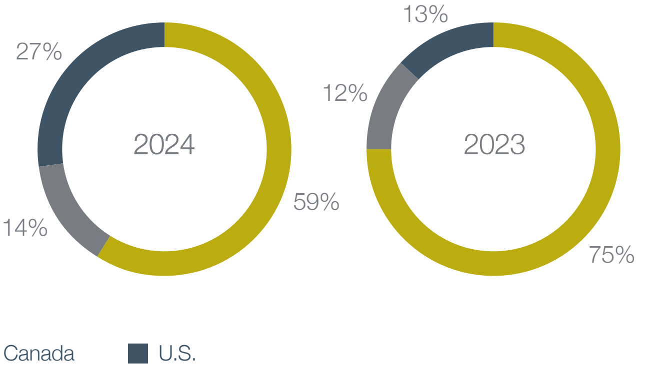
Adjusted EBITDA and revenues and other income by facility geography for the year ended December 31

Trading activity amounts directly related to facilities are included in adjusted EBITDA and revenues and other income based on the geographic location of the facility that the trading relates to. Corporate adjusted EBITDA and revenues and other income are excluded from these amounts. The acquisitions of Frederickson 1 at the end of 2023, and La Paloma and Harquahala in the first quarter of 2024 (see Significant events) boosted U.S. percentages. Combined with the lower realized power prices in Alberta compared to the previous year, this reduced the contribution from Alberta. The rest of Canada's percentages remained stable.

Adjusted EBITDA[1] by facility geography



Revenues and other income by facility geography[2]



[1] See Non-GAAP Financial Measures and Ratios.

[2] The allocation of revenues and other income by facility geography excludes the impacts of unrealized changes in fair value of commodity derivatives and emission credits.

Consolidated net income and results of operations

Energy prices and hedged positions

Alberta commercial portfolio		Year ended December 31 2024	2023
Power			
Hedged volume at beginning of period	GWh	**11,000**	10,500
Spot power price average	$ per MWh	**63**	134
Realized power price[1]	$ per MWh	**78**	90
Natural gas			
Hedged volume at beginning of period	TJ	**70,000**	51,500
Spot natural gas price average (AECO)[2]	$ per GJ	**1.29**	2.54

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

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

Alberta commercial facilities and portfolio optimization

The Alberta spot price averaged $63 per MWh for the year ended December 31, 2024 compared to $134 per MWh in the same period last year. Several factors have contributed to the year-over-year decline in Alberta spot and captured pricing for our Alberta commercial portfolio:

- moderate temperatures across Alberta throughout most of 2024 compared to 2023,
- more planned and unplanned thermal outages in the province in 2023,
- higher renewables generation from the additional capacity combined with higher capacity factors in the province compared to 2023,
- additional baseload capacity and generation in the province compared to 2023, and
- lower AECO spot pricing due to strong production and high storage levels throughout 2024.

Lower generation and availability for 2024, compared to 2023 were impacted by the following:

- planned outages in 2024 to complete simple cycle and combined commissioning for Genesee Generating Station repowered units 1 and 2,
- more frequent intermittent unplanned outages at Genesee Generating Station in the first quarter of 2024 compared to 2023,
- planned outage at Genesee Generating Station unit 3 in the second quarter of 2024 versus no outages in the comparative periods,
- longer unplanned outages at Clover Bar Energy Centre compared to 2023, and
- longer planned and unplanned outages at Shepard compared to 2023.

Lower revenues and other income and adjusted EBITDA for 2024 compared to 2023 were primarily due to reduced realized power prices for the Alberta commercial portfolio, lower generation as described above, and an insurance recovery in 2023 for an unplanned outage at Joffre in 2022.

Adjusted EBITDA benefited year-over-year from lower energy purchases and fuel costs driven by lower coal costs and lower emissions costs, partly offset by higher natural gas costs due to higher volumes procured, as the Genesee Generating Station transitioned off-coal to 100% natural gas in the year (see Significant events). Adjusted EBITDA was further impacted in 2024 compared to the same period in 2023 by higher realized natural gas prices on positions entered into during a higher-priced environment.

Western Canada facilities

Stronger generation in 2024 compared to 2023 was due to Island Generation being dispatched more in the third quarter of 2024 due to higher demand from hotter temperatures. However, since the energy purchase agreement, which is classified as a finance lease for accounting purposes, is based on availability, the decrease in revenues and other income and adjusted EBITDA was due to a decrease in finance income. In addition, revenues and other income and adjusted EBITDA slightly decreased year-over-year from lower merchant REC sales at Whitla Wind, with the decline in adjusted EBITDA slightly offset by the costs incurred in 2023 due to the wildfire impacting Quality Wind.

Consolidated net income and results of operations

Ontario facilities

Generation for 2024 benefited from increased demand on thermal facilities to backstop tight market conditions in the Ontario power market. Revenues and other income and adjusted EBITDA for 2024 were consistent compared to the previous year due to higher generation that was offset by lower prices, and slightly higher operating expenses.

U.S. facilities

Generation and availability for 2024 compared to the previous year were impacted by the following:

- stronger demand from higher temperatures, lower natural gas prices and nuclear outages leading to increased dispatch of our thermal facilities for the first nine months of the year, and
- contributions from Frederickson 1, acquired in December 2023 and from Harquahala and La Paloma, both acquired in February 2024.

Significantly increased revenues and other income and adjusted EBITDA for 2024 versus 2023 were impacted by the above factors, and the following:

- lower results from Midland Cogeneration in 2024 compared to previous year primarily from a lower gross margin driven by lower energy rates and higher first quarter fuel costs due to a January winter storm, and slightly higher maintenance and operation costs. This decrease was partially offset by higher dispatch.
- lower revenues at Arlington Valley from lower capacity payments and reduced recovery of natural gas expense in 2024 compared to 2023. However, net impacts to adjusted EBITDA from the latter were negligible as fuel costs are recovered through Heat Rate Call Option (HRCO) strike payments from the off-taker.
- Strong trading results in 2024 compared to 2023 were due to increased trading activity and higher realized gains from our power and environmental trading portfolio.

Corporate

Corporate results include (i) revenues for cost recoveries and other income related to off-coal compensation from the Province of Alberta which was fully recognized at the end of fiscal 2023, (ii) costs of support services such as treasury, finance, internal audit, legal, people services, corporate risk management, asset management, and environment, health and safety, and (iii) business development expenses. 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, 2024, were lower than the same period in 2023 partly because the off-coal compensation from the Province of Alberta was fully recognized at the end of 2023. However, the cash payment received from Province of Alberta will continue to be reflected in AFFO annually through 2030. Higher share-based incentives driven by strong share price appreciation in 2024 and higher business development costs further contributed to the lower adjusted EBITDA year-over-year.

Unrealized changes in fair value of commodity derivatives and emission credits

	Year ended December 31			
($ millions)	**2024**	2023	**2024**	2023
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income[1]**		**Income before tax[1]**	
Unrealized gains on Alberta power derivatives	**268**	414	**266**	363
Unrealized gains on U.S. power derivatives	**181**	124	**128**	124
Unrealized (losses) gains on natural gas derivatives	**(40)**	26	**(153)**	(179)
Unrealized gains on emission derivatives	**38**	–	**22**	–
Unrealized (losses) gains on emission credits held for trading	**–**	–	**(25)**	13
	447	564	**238**	321

[1] Revenues and other income and adjusted EBITDA from our Alberta commercial facilities and portfolio optimization and U.S. trading include realized changes in the fair value of commodity derivatives and emission credits but exclude unrealized changes in these values. The unrealized changes are also excluded from our adjusted EBITDA metric.
When a derivative instrument settles, the unrealized fair value changes recorded in prior periods for that instrument are reversed from this category. The gain or loss realized upon settlement is then reflected in adjusted EBITDA for the relevant facility category.

During the year ended December 31, 2024 and 2023, the Company recognized unrealized gains of $266 million and $363 million, respectively, on Alberta power derivatives due the reversal of prior period unrealized losses on positions that settled in the year and reduced forward prices on net forward sale contracts.

During the year ended December 31, 2024, the U.S. power portfolio recognized unrealized gains of $128 million on power derivatives, mainly due to decreasing forward prices on forward sales contracts on the Company's U.S. wind facilities and net unrealized gains on La Paloma spark spread hedges.

Consolidated net income and results of operations

During the year ended December 31, 2023, the Company recognized unrealized gains of $124 million on U.S. power derivatives due to net impacts of the reversal of prior period unrealized losses on positions that settled in the year and decreased forward power prices on net forward sales contracts related to the Company's U.S. wind facilities.

During the years ended December 31, 2024 and 2023, Capital Power recognized unrealized losses on natural gas derivatives of $153 million and $179 million, respectively, due to impacts of decreasing pricing on forward purchase contracts, partially offset by the reversal of prior period unrealized losses on positions that settled during these periods.

During the year ended December 31, 2024, Capital Power recognized unrealized gains on emissions derivatives of $22 million, mainly due to favourable impacts of increased forward prices on forward purchases. During the year ended December 31, 2023, the Company recognized no net unrealized gains or losses due to the impacts of higher pricing on long positions offset by the reversal of prior period unrealized gains on positions that settled in the year.

During the year ended December 31, 2024, the Company recognized unrealized losses on emissions credits held for trading of $25 million mainly due to the reduction in inventory and the reversal of prior period gains that settled in the period. During the year ended December 31, 2023, the Company recognized unrealized gains of $13 million on emissions credits held for trading due to the impacts of increased pricing on additional inventory held, partially offset by the reversal of unrealized gains on inventory sold.

Consolidated other expenses and non-controlling interests

	Year ended December 31	
($ millions)	**2024**	2023
Interest on borrowings less capitalized interest	**(214)**	(154)
Realized gains on settlement of interest rate derivatives	**14**	34
Other net finance expense – interest on off-coal compensation from the Province of Alberta, lease liability interest, sundry interest, guarantee and other fees	**(2)**	(9)
	(202)	(129)
Fair value changes on interest rate derivatives	**–**	(14)
Other finance expense – amortization and accretion charges, including accretion of deferred revenue for off-coal compensation from the Province of Alberta	**(19)**	(23)
Total net finance expense	**(221)**	(166)
Depreciation and amortization	**(503)**	(574)
Impairment	**(27)**	–
Foreign exchange loss	**(29)**	(6)
Gain on divestiture	**309**	–
Losses on disposals and other transactions	**(31)**	(3)
Other items from joint ventures[1]	**(123)**	(81)
Income tax expense	**(187)**	(204)
Net (income) loss attributable to non-controlling interests	**(2)**	7

[1] Includes finance expense, depreciation expense and fair value changes on derivatives from joint ventures.

Consolidated net income and results of operations

Net finance expense

Higher net finance expense for the year ended December 31, 2024 compared with the prior year largely reflects higher interest on increased loans and borrowings. This is due to the $850 million and $350 million medium-term notes issued in the second half of 2023 and $1 billion of debt financing issued during 2024 (see Significant events). Lower realized gains on settlement of interest rate derivatives also contributed to higher net finance expense for the year ended December 31, 2024. This was partially offset by higher capitalized interest from the continued advancement of Halkirk 2 Wind and Ontario growth projects throughout 2024, higher interest income on proceeds of financing for Harquahala and La Paloma acquisitions in the first quarter of 2024, and lower accretion charges incurred due to full recognition of off-coal compensation at the end of 2023.

Depreciation and amortization

Lower depreciation and amortization for the year ended December 31, 2024 compared with the prior year were primarily due to the original units 1 and 2 of Genesee Generating Station and Genesee Mine assets being fully depreciated at the end of 2023. The decrease was partly offset by increased depreciation for assets acquired in the Frederickson 1 and La Paloma transactions that occurred in December 2023 and February 2024, respectively (see Significant events), and the increased depreciation from the commissioning of Genesee Repower 1 and 2 in late 2024 (see Significant events).

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 (see Significant events). 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 interest sold and $158 million upon remeasurement of Capital Power's remaining 51% interest to its fair value when control was lost.

Losses on disposals and other transactions

Losses on disposals and other transactions for the year ended December 31, 2024 mostly reflects a provision for a pre-tax cost of $18 million incurred as part of the discontinuation of the Genesee Generating Station CCS project related to termination of sequestration hub evaluation work (see Significant events), and an accrual for additional Genesee Mine decommissioning costs.

Other items from joint ventures

Other items from joint ventures includes Capital Power's share of finance expense, depreciation expense and fair value changes on derivatives from our Quality Wind, York Energy, Port Dover and Nanticoke Wind, Midland Cogeneration and Harquahala joint ventures, which are accounted for under the equity method. Other items from joint ventures increased compared with 2023 primarily due to the acquisition of the Harquahala joint venture in the first quarter of 2024.

Income tax expense

Income tax expense for year ended December 31, 2024 decreased compared to 2023 primarily due to lower overall consolidated net income before tax, partially offset by tax related to the renewable power asset sell-down transaction (see Significant events).

Non-controlling interests

Non-controlling interests mostly consists of the Genesee Mine partners' shares of the consolidated net income of these facilities. The Genesee Mine was fully depreciated at the end of 2023.

Comprehensive income

	Year ended December 31	
($ millions)	**2024**	2023
Net income	**701**	737
Other comprehensive income (loss):		
Actuarial gains (losses) related to the Company's defined benefit pension plan	**1**	(2)
Net unrealized gains on derivative instruments	**81**	155
Net realized (gains) losses on derivative instruments reclassified to net income	**(25)**	160
Equity-accounted investments	**4**	(3)
Unrealized foreign exchange gains (losses) on the translation of foreign operations	**218**	(31)
Total other comprehensive income, net of tax	**279**	279
Comprehensive income	**980**	1,016

Other comprehensive income includes fair value adjustments on financial instruments used to hedge market risks and which meet hedge accounting criteria. If these hedges are ineffective, gains or losses are recognized in net income. Other unrealized fair value changes on derivative instruments designated as cash flow hedges and foreign currency translation gains or losses are recognized in net income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated.

Financial position

The significant changes in the consolidated statements of financial position from December 31, 2023 to December 31, 2024 were as follows:

($ millions)	**December 31, 2024**	December 31, 2023	**Increase (decrease)**	**Business acquisitions and divestitures**[1]	**Other**	**Primary reason for increase (decrease)**
Trade and other receivables	**604**	747	(143)	11	(154)	Timing and amount of AESO pool receipts driven by lower Alberta pool prices and lower generation.
Inventories	**235**	309	(74)	5	(79)	Depletion of coal inventory with off-coal milestone achieved in 2024 (see Significant events), and changes in emission offsets held for trading.
Government grant receivable	**380**	269	111	–	111	Accrual of Clean Technology investment tax credits (ITCs) on eligible projects partly offset by receipt of annual off-coal compensation from the GoA.
Equity-accounted investments	**1,096**	455	641	655	(14)	Impairment on investment in C2CNT and distributions received, partly offset by our share of net income from the investments.
Intangible assets and goodwill	**744**	775	(31)	188	(219)	Use of emission credits for plant compliance and ongoing amortization.
Property, plant and equipment	**8,061**	6,557	1,504	477	1,027	Ongoing construction of growth projects and impact of increasing foreign exchange rates, partly offset by depreciation.
Trade and other payables	**751**	717	34	106	(72)	Lower trading margin driven by decreasing forward natural gas prices on net forward purchase contracts, lower accrued power costs for commercial and industrial customers due to lower Alberta pool pricing and lower emission compliance costs due to lower generation.
Subscription receipts liability	**–**	399	(399)	–	(399)	Conversion of subscription receipts to common shares upon closing the La Paloma and Harquahala acquisitions in February 2024.
Net derivative financial instruments assets (liabilities)	**15**	(248)	263	–	263	Impact of decreasing forward power pricing in Canada and U.S. on net forward sale contracts, partly offset by the impact of decreasing forward natural gas and emissions pricing on forward purchase contracts.
Loans and borrowings (including current portion)	**4,976**	4,716	260	–	260	Issuance of $1 billion in debt (see Significant events). Partly offset by $450 million debt maturity in September 2024, repayments of U.S. credit facilities, Canadian dollar bank loans and impact of increasing foreign exchange rates.
Net deferred tax liabilities	**837**	661	176	–	176	Increase primarily due to recognition of taxable temporary differences and changes in derivative financial instrument balances.
Net deferred revenue and other liabilities	**536**	302	234	–	234	Accrual of Clean Technology ITCs on eligible projects, and additional supplier finance arrangements partly offset by payments of deferred financing on capital projects.

[1] Includes the impacts of the La Paloma and Harquahala acquisitions and the Quality Wind and Port Dover and Nanticoke Wind divestitures (see Significant events).

Liquidity and capital resources

($ millions)	Year ended December 31		
Cash inflows (outflows)	**2024**	2023	Change
Operating activities	**1,144**	822	322
Investing activities	**(1,916)**	(807)	(1,109)
Financing activities	**202**	1,103	(901)

Operating activities

Cash flows from operating activities increased compared to the same period in 2023 mainly due to favourable changes in non-cash operating working capital (see Financial position), reduced income taxes paid and increased distributions received from joint ventures. Partially offsetting these increases are lower fair value changes reflected as cash settlements during 2024 compared with the same period in 2023, decreased adjusted EBITDA described in Consolidated Net Income and Results of Operations and higher interest paid on borrowing. Fair value changes are most notably driven by the impact of greater decreases in forward power prices on net forward sale contracts in 2023. These fair value changes in certain unsettled derivative financial instruments are credited to the Company's bank margin account held with a specific exchange counterparty.

Investing activities

Cash flows used in investing activities increased compared with the prior year due to higher capital expenditures for the repowering of Genesee Generating Station units 1 and 2, Ontario growth projects, Halkirk 2 Wind, Maple Leaf Solar and commercial initiatives, and the acquisitions of La Paloma and Harquahala in February of 2024 (see Significant events). Partly offsetting these is proceeds from the partial divestiture of Quality Wind and Port Dover and Nanticoke Wind (see Significant events).

Liquidity and capital resources

Capital expenditures and investments

		Year ended December 31				
($ millions)	Pre-2023 actual	2023 actual	**2024 actual**	2025 estimated[1,2]	Actual or projected total[2]	Targeted completion
Repowering of Genesee 1 and 2[3]	644	409	**434**	63 – 163	1,550 – 1,650	Achieved commercial operations fourth quarter of 2024 (see Significant events)
Halkirk 2 Wind[4]	1	68	**229**	13	311	First half of 2025
Ontario growth projects[5]	–	19	**337**	204	600	York Energy and Goreway BESS in 2025 East Windsor Expansion in 2026
Maple Leaf Solar[6]	–	2	**10**	50	219	First quarter of 2027
Bear Branch Solar	3	3	**2**	48	103	Second half of 2026
Hornet Solar	3	3	**9**	90	187	Second half of 2026
Hunter's Cove Solar	3	1	**–**	N/A	N/A	Terminated
Clydesdale Solar	121	4	**–**	N/A	125	Operations commenced December 2022
Commercial initiatives[7]	196	18	**54**	24		
Development sites and projects	62	1	**–**	–		
Subtotal growth projects		528	**1,075**	492 – 592		
Sustaining – plant maintenance excluding Genesee mine		101	**162**			
Total capital expenditures[8]		629	**1,237**			
Emission credits held for compliance		36	**13**			
Capitalized interest		(41)	**(56)**			
Additions of property, plant and equipment and other assets		624	**1,194**			
Change in other non-cash investing working capital and non-current liabilities		99	**(124)**			
Purchase of property, plant and equipment and other assets, net		723	**1,070**			

[1] The Company's 2025 estimated capital expenditures include only expenditures for previously announced growth projects and exclude other potential new development projects.

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

[3] Projected costs for the project including post-commercial operations date.

[4] The targeted completion date for Halkirk 2 Wind has been revised from the fourth quarter of 2024 to the first half of 2025. This delay is due to a site-wide stand-down resulting from a nacelle and rotor at one of the turbines falling from the tower in November 2024.

[5] Projected total costs have been revised for reduced lithium carbonate commodity costs due to contract execution with supplier.

[6] Targeted completion for Maple Leaf Solar has been updated to reflect a change in timing of the execution of an interconnection agreement.

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

[8] 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

Cash flows from financing activities decreased in the year ended December 31, 2024 compared with the prior year, mainly due to the repayment of the $450 million medium-term notes and U.S. credit facilities, lower proceeds from the issuances of medium-term notes and redemption of preferred shares during 2024. This decrease was partially offset by the issuance of share capital (see Significant events).

Capital Power's credit facilities consisted of:

		At December 31, 2024			At December 31, 2023		
($ millions)	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	Total facilities	Credit facility utilization	Available
Committed credit facilities	2029	**1,000**			1,000		
Letters of credit outstanding			**–**			–	
Bankers' acceptances outstanding			**–**			–	
Bank loans outstanding[1]			**–**			266	
		1,000	**–**	**1,000**	1,000	266	734
Bilateral demand credit facilities	N/A	**1,421**			1,387		
Letters of credit outstanding			**608**			559	
		1,421	**608**	**813**	1,387	559	828
Demand credit facilities	N/A	**25**	**–**	**25**	25	–	25
		2,446	**608**	**1,838**	2,412	825	1,587

[1] U.S. dollar denominated bank loans outstanding totalling US$201 million at December 31, 2023.

At December 31, 2024, the committed credit facility utilization decreased $217 million compared with December 31, 2023 due to repayment of U.S. bank loans. 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, 2024, $99 million of bonds were issued under these facilities (December 31, 2023 – $77 million).

Capital Power holds a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P) which was affirmed in March 2024. The BBB rating category assigned by S&P is the fourth highest within their ten-tier rating system for long-term debt obligations. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments; however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

Capital Power has a corporate credit rating of BBB (low) with a stable trend from DBRS Limited (DBRS), which was affirmed in April 2024. The BBB rating category assigned by DBRS is the fourth highest rating of DBRS's ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality and the capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.

The above credit ratings from S&P and DBRS are investment grade, enhancing 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 net tangible assets to consolidated net tangible 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 of less than BBB- by S&P and less than BBB (low) by DBRS.

As of December 31, 2024, Capital Power has met the financial covenants set out in the respective loan and credit agreements.

Liquidity and capital resources

Future cash requirements

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's expected cash requirements for 2025 include:

($ millions)	2025 expected cash requirements
Repayment of debt payable[1]	**83**
Interest on loans and borrowings	**257**
Capital expenditures – sustaining	**210**
Capital expenditures – ongoing growth projects[2]	**564**
Capital expenditures – commercial initiatives	**24**
Common share dividends[3]	**289**
Preferred share dividends	**28**
	1,455

1 Excludes repayment of credit facilities.

2 Includes repayments of deferred capital expenditures on the Genesee repowering project.

3 Includes 6% annual dividend growth, subject to approval by the Board.

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 through various agreements, particularly with respect to our PPA, 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.

Off-statement of financial position arrangements

At December 31, 2024, Capital Power has $608 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

	At December 31	
($ millions)	**2024**	2023
Loans and borrowings	**4,976**	4,716
Subscription receipts[1]	**–**	399
Lease liabilities[2]	**151**	147
Less cash and cash equivalents	**(865)**	(1,423)
Net debt	**4,262**	3,839
Share capital	**4,301**	3,524
Deficit and other reserves	**275**	(334)
Non-controlling interests	**(5)**	(4)
Total equity	**4,571**	3,186
Total capital	**8,833**	7,025

1 Capital Power's obligation for converting subscription receipts to common shares of Capital Power that have been converted upon the closing of La Paloma acquisition (see Significant events) in February 2024.

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

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						
(unaudited, $ millions)	2025	2026	2027	2028	2029	Thereafter	Total
Loans and borrowings[1]	84	640	495	445	266	2,836	4,766
Interest on loans and borrowings	257	242	209	191	162	510	1,571
Trade and other payables[2]	681	–	–	–	–	–	681
Lease liabilities	27	16	15	15	15	185	273
Capital – growth projects[3]	536	376	54	34	–	–	1,000
Capital – commercial initiatives[4]	24	12	–	–	–	–	36
Decommissioning provisions[5]	34	34	17	–	–	632	717
Energy purchase and transportation contracts[6]	286	300	220	120	81	219	1,226
Operating and maintenance contracts	113	88	87	91	90	546	1,015
Environmental credits[7]	189	303	41	66	19	20	638
Commodity and other derivative liabilities net of financial assets	41	49	49	40	40	100	319
Total	**2,272**	**2,060**	**1,187**	**1,002**	**673**	**5,048**	**12,242**

[1] Repayments of loans and borrowings exclude fair value differentials of $9 million related to debt assumed on previous asset acquisitions and $237 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 the repowering of Genesee Generating Station units 1 and 2, 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 2025. These obligations exclude interest to fund construction of $52 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 2025 to 2037.

[7] Future environmental credit purchases are presented net of future environmental credits 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 arising from these claims is immaterial and therefore no provision has been made.

A dispute has arisen between the Company and the contractor regarding construction work on the Genesee Repowering Project. The parties are actively participating in an agreed-upon mediation process to resolve the claims by both parties. The Company has withheld payments pending the resolution of the dispute which is at a preliminary stage. The Company is still reviewing the claims and at this time the outcome of the mediation process is uncertain.

Other legal matters

From 2017 through 2023, the Government of Alberta (GoA) withheld approximately $2.7 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.

In addition, the GoA amended its Linear Property Assessment Guidelines (the Guidelines) in 2017 to eliminate the anticipated cessation of coal emissions (and related business closures) from being considered in property tax assessments, which erroneously suggests that the off-coal payments were intended to compensate the Company for non-net book value related costs. In response, Capital Power and TransAlta jointly commenced litigation on the basis that the Guidelines discriminatorily applied only to three coal generators. The Court of King's Bench issued a decision on January 15, 2021 rejecting all of Capital Power and TransAlta's arguments and the Alberta Court of Appeal issued a decision on November 23, 2022 unanimously rejecting the joint appeal that was submitted. Capital Power has decided to not pursue leave to appeal to the Supreme Court of Canada (SCC). If TransAlta is granted leave to the SCC, Capital Power will remain a named appellant only for the purposes of the hearing.

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. 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. The Company believes the various agreements governing the termination and transfer of the Sundance C PPA and related transmission agreements with the AESO had the effect of transferring all past liabilities for the Sundance C PPA to the Balancing Pool. Capital Power has therefore filed a statement of claim at the Alberta Court of Queen's Bench on January 11, 2021 against the Balancing Pool, the Province of Alberta and the AESO in which it is seeking, among other relief, recovery from the Balancing Pool and the Province of Alberta of all amounts Capital Power was compelled to pay to the AESO on account of the LLR adjustment invoices relating to the Sundance C PPA as well as interest and legal costs, including the portion invoiced to the Balancing Pool but not received by the Company pertaining to all tranches of invoices. In September 2024, Capital Power filed a Partial Discontinuance of Claim discontinuing its claim only as against the AESO. This process remains ongoing. Capital Power continues to expect that it will ultimately realize the full amount of the gross receivables related to line losses upon resolution of the dispute before the Court.

Risks and risk management

Events within and outside of Capital Power bring both risk and opportunity. Effective risk management is a critical factor in protecting shareholder value. The principles of risk management are embedded into all aspects of our operations to ensure risks are effectively managed across the organization. We view risk management as an ongoing process and continually look for ways to enhance our risk management programs and procedures.

Capital Power maintains strong risk governance and oversight practices with the Board and its committees' terms of reference outline risk oversight responsibilities. Our Board is responsible for understanding Capital Power's principal risks and determining whether the Company achieves a proper balance between risk and returns and that Management ensures that systems are in place to address the risks identified. The Company employs an ERM program to support the Board's governance requirements and the Company's overall risk monitoring and management.

Capital Power's ERM Program aligns with the Committee of Sponsoring Organizations' standard for enterprise risk management and is supported by our ERM policy framework. The ERM program is the mechanism used to identify, assess, categorize, respond to, report on, and monitor key risks. Risks are assigned to individual executive risk owners who are accountable for carrying out the risk management and response strategies, with the President and CEO having ultimate accountability for managing the Company's risks.

Our ERM program uses a systematic approach to perform risk assessments with subject matter experts across Capital Power. A comprehensive analysis of the risk assessments are reported to the Board quarterly. Results of the risk assessments are also shared with Capital Power's Internal Audit team to inform the annual risk-based internal audit plan. This audit plan seeks to provide the Board and Management with independent assurance that key risks are being effectively managed and that the systems of internal controls are properly designed and working effectively.

In addition to the ERM program, Capital Power has risk management and compliance functions across the organization, including in the Finance, Legal, Operations and Planning departments.

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 execution

While assessing development and acquisition opportunities, Capital Power may be required to incur significant expenditures, such as those related to preliminary engineering, permitting, legal and other expenses, before determining whether a project is feasible and economically viable. Competition on acquisition and development opportunities is significant, and there can be no assurance that Capital Power will pursue or win any opportunity assessed.

The risks associated with acquisitions of additional companies or assets in the power generation industry include the failure to identify material problems during due diligence, the overpayment for assets and the inability to arrange financing for an acquisition. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will cover the cost of financing incurred to acquire them or the capital expenditures needed to develop them.

Capital Power must complete numerous tasks in its development and construction projects. Tasks include obtaining government permits and approvals, site agreements, construction contracts, access to power grids, access from landowners, electrical transmission agreements, fuel supply and transportation agreements, equipment, and financing. There can be no assurance that Capital Power will be successful in completing such tasks on a timely basis or at all. The development and future operation of our projects can be adversely affected by changes in government policy and regulation, environmental concerns, stakeholder activism, inflation, increases in capital costs, shipping delays, increases in interest rates, competition in the industry, labour and parts availability, labour disputes, increases in material costs, our ability to secure off-take agreements and other matters beyond the control of Capital Power. If a project is not completed or does not operate at anticipated performance levels, Capital Power may not be able to recover its investment.

The acquisitions of La Paloma and Harquahala closed on February 9, 2024, and February 16, 2024, respectively (see Significant events). These acquisitions are a major step for Capital Power's strategic growth and expansion within the U.S. energy market. However, these transactions also introduce several growth execution risks that need to be effectively managed to ensure the anticipated benefits are realized.

Capital Power must effectively manage infrastructure and the expansion of our workforce, which includes developing our team members to support and integrate these new operations. Additionally, Capital Power must also effectively manage our operations, including potential interactions with workers' councils and trade unions. Our expansion into the U.S. exposes us to various economic, political, and other risks associated with global operations. This includes navigating new or uncertain regulatory environments, managing geopolitical risks, and addressing operational challenges in the respective communities.

Risks and risk management

La Paloma is contracted under various resource adequacy contracts through 2029 with multiple investment grade utilities and load serving entities, while Harquahala is 100% contracted under a tolling agreement through 2031 with an investment-grade utility. These long-term contractual commitments present growth execution risks, such as meeting performance obligations, renegotiating and renewing contracts on favourable terms, and managing counterparty creditworthiness. Changes in energy demand, regulatory policies, and market conditions could impact the value and performance of these contracts, affecting future revenue streams and profitability. Additionally, the partnership with BlackRock carries risks related to joint venture management.

Capital Power's growth strategy anticipates power demand growth in North America from trends including electrification, industrial reshoring, population growth and AI. Power demand growth may not materialize as anticipated due to a number of factors, including the advancement in AI technologies, energy efficiencies gained from other disruptive technologies, and other unforeseen factors, which could impact Capital Power's growth strategy.

The Company continues discussions with counterparties around possible power supply arrangements for data centres. Hence, it is crucial to consider the unique challenges associated with providing power to data centres. These facilities require an exceptionally reliable and uninterrupted power supply to support their critical operations, and any disruptions can result in significant operational and financial implications. The risk of power outages, whether due to natural disasters, equipment failures, or cyber-attacks, poses a substantial threat. Additionally, the increasing demand for power from data centres can strain existing infrastructure, necessitating substantial investments in grid upgrades and maintenance.

Strategies employed for managing growth execution risk:

- Maintain strong governance and oversight. Examples include:
  - Business development opportunities are pursued in consultation with the Board and in accordance with the Company's corporate long-term plan and corporate strategy.
  - Internal policy in place to govern the process for how Capital Power develops business opportunities from the initial phase through to the integration of an asset into the Company. This process provides a framework for accountability and helps identify and mitigate risks associated with major projects.
  - Strong project management.
- Perform detailed project analyses, risk assessments and due diligence, including exploring opportunities to add operational value, prior to and during construction or acquisition.
- Annual review of hurdle rates.
- Perform post-implementation evaluation of all major projects to improve internal capabilities and processes and to leverage lessons learned for future projects. When necessary, corrective actions are taken to increase the likelihood of investment recovery.
- Establish a development pipeline in target markets.
- Enter favourable long-term contracts for projects' output, minimizing the time between commercial operation dates and contract signing, whenever possible.
- Establish and maintain constructive relationships with suppliers and stakeholders, including collaborative contracting for construction projects.
- Follow established data centre opportunity screening criteria.

Power price

Capital Power is impacted by the market price for power in the jurisdictions and markets where the Company has un-contracted generation exposure, the largest exposure being in the Alberta power and California power markets. Market power prices are dependent on a number of factors, including electricity supply and demand, the cost and availability of natural gas, applicable environmental and regulatory compliance costs, competitors' bidding strategies, power market structures, and weather conditions. It is not possible to predict future power prices with certainty, and power price volatility could have a material effect on Capital Power.

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. 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. 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.

Capital Power is also exposed to node-to-hub basis risk at many of its U.S. facilities. Basis risk is the difference between the power price at the node, where the power is produced, and the hub, where the power is financially settled with the off-taker. This risk can be exacerbated by events such as transmission congestion and extreme weather.

Risks and risk management

Strategies employed for managing power price risk:

- Maintain strong governance and oversight. Examples include:
  - Risk Oversight Council (consisting of senior management representatives appointed by the President and CEO) which establishes the structure, conduct and control of Capital Power's commodity exposure management program, both in physical and financial derivatives markets.
  - Maintain a commodity risk management program which provides the infrastructure to manage commodity and trading risks associated with the commodity business.
  - Take market risk positions within authorized limits approved by Capital Power's Executive Team and the Board. The Company operates under specific policy limits, such as total commodity risk and stop-loss limits, and generally trades in electricity to reduce the Company's exposure to changes in electricity prices or to match physical or financial obligations.
  - The Executive Team has access to daily risk reports which provide key risk measures in relation to applicable limits and quarterly risk reports are reviewed by Capital Power's Audit Committee.
- Contract generation facilities under new or extended contracts to maintain a balance of contracted and non-contracted facilities.
- Invest in operational efficiencies to maintain the competitiveness of the Company's assets in the supply stack.
- Limit exposure to market price volatility by entering long-term power contracts. Examples include contracts-for-differences, back-to-back physical and financial contracts to lock in a margin, heat rate call options, and other long-term fixed price contracts.
- Perform regular commodity portfolio stress testing to observe the effects of plausible scenarios considering historical price movements and certain hypothetical extreme events.
- Proactively forecast exposure to price fluctuations. To do this, Capital Power relies on proprietary forecasting models in concert with third-party service providers.
- Continually evolve the sophistication of our risk management program and our strong expertise in the jurisdictions in which we operate.

Fuel supply and price

Capital Power requires energy from sources such as natural gas, wind, and the sun to generate electricity. A disruption in the supply, a significant increase in the price of supply or the availability of these sources could have a material adverse strategic and financial impact on Capital Power.

The price of natural gas depends on supply and demand fundamentals for natural gas across North America and globally.

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. Forward buying may result in losses if the assets for which that gas is bought are unexpectedly unavailable.

Capital Power's natural gas-fired facilities which are un-contracted are susceptible to the risks associated with the volatility of natural gas 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 depends on pipeline infrastructure owned and operated by external parties to deliver natural gas to its natural gas facilities. If the infrastructure is inadequate to supply natural gas, there may be a material adverse effect on Capital Power's ability to produce power from those facilities. Capital Power procures firm transportation services where warranted with pipeline companies to ensure the delivery of natural gas and has insurance coverage to mitigate, but not eliminate, business interruption risk.

Capital Power's wind and solar power facilities are dependent on the availability and constancy of sufficient wind and solar resources to meet projected capacity factors or production target requirements in tax-equity financing arrangements. Fluctuations in wind speed, direction or duration, as well as hours of sunlight could have a material negative impact on revenues and cash allocations for these facilities in any year.

Strategies employed for managing fuel supply and price risk:

- The strategies described in power price risk above, such as the Risk Oversight Council, commodity risk management program, corporate governance over market positions and key risk measures and commodity portfolio stress testing also apply to fuel supply and price risk related to natural gas.
- Fuel-type diversification across our fleet.
- Establish long-term natural gas transportation agreements and storage capabilities, where applicable.
- Establish contracts with fuel cost, including carbon cost, flow-through provisions, where possible.
- Limit exposure to market price volatility by entering natural gas hedges. Examples include contracts-for-differences, and back-to-back physical and financial contracts to lock in a margin.
- Manage compliance costs via an active presence in environmental commodity markets.
- Ongoing asset optimization initiatives targeting efficiency and performance improvements.
- Thorough due diligence on natural gas supply, wind and solar data prior to development or acquisition of facilities.

Risks and risk management

Cyber-security and systems

Capital Power's ability to carry out its normal business processes is dependent on the performance and security of the key information and operational technology systems that support its core operations. Cyber attacks on the Company or through our supply chain continue to be a risk and could result in the loss or misuse of sensitive information or damage to physical assets and have significant adverse impacts on the Company's operations. Failure of key information or operational technology systems, during or after implementation, could result in significant lost revenues, increased costs or regulatory fines, and reputational damage.

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 rigorous cyber-security training and awareness program.

The increase in Capital Power's use of AI in its operations may impact Capital Power's data privacy and security, as AI systems require vast amounts of data, including sensitive information. This increases the potential for data breaches and unauthorized access. Over-reliance on AI systems can also lead to decisions and reporting based on inaccurate or non-validated information, skillset changes, as well as other changes in workforce requirements.

Strategies employed for managing cyber-security and systems risk:

- The Cyber Security Leadership Council, comprised of senior leaders from various areas of the Company, meets regularly to monitor the effectiveness of the strategies below and to address new and evolving risks.
- Disaster recovery and backup plans to ensure critical systems and processes can be recovered in the event of a cyber attack.
- Automated and AI backed monitoring of the Company's information and operational technology systems, logs, and security events.
- Regular communication with external governmental and industry groups to share threat intelligence, trend analysis, and best practices.
- Periodic external audits of the effectiveness of the Company's information and operational technology security systems and annual penetration tests.
- System safeguards to combat the ever-increasing sophistication in phishing attacks.
- AI monitoring of data movement.
- AI monitoring of phishing emails.
- Ongoing role-based user cyber-security training and awareness program.
- Compliance with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standards, based on each respective asset's categorization and the applicable regulatory region's requirements.
- Minimize the customization of commercial software, monitor impacts on processes and internal controls and undertake remedial actions, if required.
- Ensure implementation projects are properly resourced with qualified and trained staff and contractors.
- Employ change management to ensure all enhancements are fully tested and approved, prior to production deployment.
- Regular internal and external tabletop/simulated exercises.
- Implementation of a Supply Chain Cyber Risk Mitigation Plan.
- Management approves new AI tools or products with a focus on the vendors' adherence to best practices on data security.
- Role-based cybersecurity training to employees which includes guidelines for the appropriate use of AI.

Climate change

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. In late 2024, we reassessed our 2030 interim and 2045 net zero targets considering projected market conditions as well as our corporate strategy. As a result, we have made the decision to retire both our 2030 interim and 2045 net zero targets and refresh our approach to sustainability to concentrate on purposeful actions which will directly improve our overall sustainability performance. By way of example, we continue to optimize our existing fleet through operational improvements and explore and invest in technologies and infrastructure to reduce emissions for utility-scale power generation.

This shift presents several risks to the Company incorporated in other subsections of this Risks and risk management section including growth execution, power price, fuel supply and price, supply chain, operation and maintenance of equipment, people, political, regulatory, business resilience, disruptive technology, stakeholder activism, and reputation risks. In addition, Capital Power's roadmap to a lower-carbon economy is based on numerous assumptions listed in our Forward-Looking Information section, and changes to these assumptions may impact the Company's progress on the roadmap.

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 lower 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.

Risks and risk management

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 (see Significant events). Capital Power has integrated sustainability into our corporate strategy and long-term planning process to monitor these trends and assess opportunities to ensure the resilience of our strategy.

Strategies employed for managing climate change risk:

- Our core flexible generation, renewables and trading and origination business lines provide balanced energy solutions that are reliable, affordable and increasingly lower-carbon.
- Monitoring and pursuing feasibility studies in promising low-carbon technologies such as CCS and SMRs.
- Advancing our decarbonization efforts through the completion of our Genesee Repowering project, beginning construction of our Ontario BESS projects, advancing our joint SMR feasibility study, and continuing to develop our pipeline of renewables.
- 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.
- Proactive pursuit of opportunities to enhance fleet reliability and efficiency through our ongoing Ops 2030 initiative.
- Due diligence for all development projects, acquisitions and commercial decisions, considering technology selection, jurisdiction, siting, environmental risks and scenarios and sensitivity analysis for carbon price and policy.
- Actively monitoring the insurance market for material changes to insurance policies that may affect the Company's ability to seek coverage for high-risk assets.

Supply chain

In the course of its day-to-day operations and the construction of development projects, Capital Power procures goods and services from a diverse range of suppliers, spanning local to international markets. Some of the goods procured are specialized parts that are essential for operating our facilities and have naturally long lead times. Supply chain and labour challenges have been prevalent throughout 2024. This has resulted in a dynamic supply chain landscape where availability and extended lead times have become the normal course of business. Disruption, inflation, or price volatility within Capital Power's supply chain could delay construction of development projects, require significant additional expenditures, and/or disrupt operations. Unsustainable practices within Capital Power's supply chain could put the long-term resilience of our supply chain at risk and have reputational impacts to the Company.

The new U.S. administration under President Trump has stated its intentions to impose new or increased tariffs on imported goods from several countries, including Canada. These tariffs may increase the cost of materials and equipment needed for our facilities, potentially affecting our profitability and the timely execution of our projects. The details of these tariffs, including which countries, which products would be included, the new rates, and the potential timing, are currently unknown.

Strategies employed for managing supply chain risk:

See Operation and maintenance of equipment risk for strategies employed that also apply to managing the Company's supply chain exposure to specialized parts in the operation of its facilities.

- Maintain an inventory of critical spares.
- Project planning and key part orders being placed earlier to account for availability shortages.
- Establish and maintain constructive relationships with key suppliers.
- Maintain multiple sources for a good or service wherever possible.
- Having a Sustainable sourcing strategy. Key aspects include:
  - Sourcing from a diverse set of suppliers including local and indigenous sources where practical, which can reduce transportation costs and require less lead-time as well as improve the economic well-being in the communities we operate and where our employees live.
  - Establishing minimum standards related to human rights and environmental considerations, which can mitigate reputation risks and prioritize sustainable practices to ensure long-term supply chain resilience.
  - Verifying that prospective suppliers comply with sustainability best practices.
- Entering purchase commitments to lock in prices.
- Internal policy that requires Board reapproval for cost overruns exceeding a certain threshold.

Risks and risk management

Operation and maintenance of equipment

Failure of generation equipment, transmission lines, pipelines or other equipment and availability of water for cooling could impede the Company's ability to maintain reliable operations of its facilities. It is possible that staffing levels at our facilities in the future could be limited by the availability of healthy staff and required external service providers due to future pandemics. Global supply chain issues could also impact the timely availability of parts and equipment.

The inability of Capital Power's generation facilities to generate the expected amount of electricity to be sold under contract or to the applicable market could have a significant adverse impact on the Company's revenues. 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. To the extent that facility equipment requires significant capital and other operation and maintenance expenditures to maintain efficiency, requires longer than forecast downtimes for maintenance and repair, experiences outages due to equipment failure or suffers disruptions of power generation for other reasons, Capital Power's cost of generating electricity will increase and its revenues may be negatively affected. As an adopter of new technology, Capital Power can be exposed to design flaws or other issues, the impacts of which may not be covered by warranties or insurance. The failure of Capital Power's facilities to operate at required capacity levels may result in the facilities having their contracted capacity reduced and, in certain cases, Capital Power having to make payments on account of reduced capacity to power purchasers.

The terms of the PPAs for owned facilities provide appropriate incentives to facility owners to keep the facilities well maintained and operational. They also provide force majeure protection for high-impact, low-probability events including major equipment failure.

Many of Capital Power's generation facilities operate under PPAs or other similar contracts which are subject to a number of risks. PPA contracts contain performance benchmarks that must be achieved and other obligations that must be complied with by Capital Power. Capital Power may incur charges in the event of unplanned outages or variations from the contract performance benchmarks. 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.

Capital Power depends on transmission facilities owned and operated by external parties to deliver the wholesale power from its power generation facilities to its customers. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, there may be a material adverse effect on Capital Power's ability to sell and deliver wholesale power.

Strategies employed for managing operation and maintenance of equipment risk:

See Business resilience for certain strategies that also apply to managing operation and maintenance of equipment risk.

- Establish long-term service agreements with original equipment manufacturers (OEMs) on key assets including access to replacement components to limit down time in the event of a unit failure.
- Ensure constructive relationships with OEMs.
- Maintain an inventory of strategic spare parts which can reduce downtime in the event of failure.
- Execute appropriate operating and maintenance standards, procedures and programs to ensure high reliability and availability of our facilities.
- Employ a root cause analysis program to ensure that problems are properly identified and addressed and that learnings are shared across the fleet.
- Complete internal audits and loss control visits on a rotational basis across the fleet.
- Ensure operations and sustainment projects are properly resourced with qualified and trained staff and contractors.
- Establish and maintain appropriate business interruption, property, and boiler and machinery insurance to reduce the impact of prolonged outages caused by insured events.
- Thorough due diligence on the adequacy of transmission capacity infrastructure for acquisitions.

People

People are at the heart of our business and the Company places a strategic focus on attracting the right people and creating an experience where they remain engaged, motivated, and empowered. Capital Power's ability to maintain reliable operations of its facilities and to grow the business is dependent upon this and the ability of our workforce to function normally and remain healthy, both physically and mentally.

Capital Power is experiencing a demographic shift as a significant number of its employees are expected to retire over the next several years. Failure to secure sufficient qualified labour may negatively impact Capital Power's operations or construction and development projects or may increase expenses.

Risks and risk management

On October 24, 2024, Capital Power announced the rollout of the VDP aimed to reduce its workforce of Canada-based corporate employees (see Significant events). This program was undertaken as part of 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. While the Company believes offering a VDP can manage workforce reductions fairly and transparently, it also comes with key risks. The Company experienced higher enrollment than anticipated, which includes the loss of employees with critical skills and institutional knowledge. This loss of key talent could impact the Company's ability to execute its strategic plans, disrupt ongoing operations, decrease service quality, and contribute to poor morale. In addition, the workforce reduction and associated costs may negatively impact the Company's reputation and employer brand, making it challenging to attract and retain top talent in the future.

Capital Power's current collective bargaining agreements expire periodically. Although not a common occurrence in Capital Power's history, the renegotiation of the collective agreements bears the risk of labour disruption or significant increases in labour costs. Collective bargaining agreements expiring in the near-term or currently being negotiated include:

- The Company's collective agreement with Unifor 1123 which represents maintenance workers and power engineers at the Island Generation facility, expires April 30, 2025.
- Collective agreements that will expire in December 2025 are (i) IBEW 1007, which represents employees directly engaged in the maintenance of electrical generation at the Genesee Generating Station, (ii) CSU 52 – Civic Service Union, which represents certain administrative, technical, professional and information technology employees located in the Edmonton corporate office and Genesee Generating Station, (iii) IBEW – International Brotherhood of Electrical Workers which represents employees directly engaged in the maintenance of electrical generation at the Genesee Generating Station, and (iv) the Company's collective agreement with UNIFOR 829, which represents power engineers located at the Genesee Generating Station.
- Collective agreements are currently in bargaining with Midland Cogeneration Venture (MCV) and United Steelworkers.

Strategies employed for managing people risk:

- Maintain strong people services programs and practices including flexible work arrangements, multi-faceted wellness programs, appropriate ethics and employee conduct policies and programs.
- Equity, diversity and inclusion strategy to ensure we are meeting the unique needs of our employees.
- Track employee engagement.
- Workforce and contingency planning, including implementation of transition plans and extended transition periods for selected employees leaving under the VDP, to reduce operational disruptions and ensure knowledge transfer before their departure.
- Maintain competitive compensation programs.
- Maintain succession plans for key positions.
- Maintain strong collective bargaining capability, programs, and practices.
- Career development plans and opportunities and talent management programs available to all employees.

The development, construction, ownership and operation of Capital Power's generation assets carry an inherent risk of liability related to public health, and worker health and safety due to exposure to high voltage electricity, high pressure steam, moving and rotating machinery, heavy equipment, driving, environmental hazards, and extreme weather, which can be exacerbated by climate change.

Strategies employed for managing health and safety risk:

- Maintain an organization-wide health and safety culture and system with regular measurements and compliance audits.
- Maintain facility-specific safety programs and work procedures.
- Maintain a robust, hybrid work environment granting employees the flexibility of working remotely to limit the potential for spreading illness through the workplace.
- Ensure that contractors and other stakeholders align with Capital Power's health and safety policies and procedures.

Capital Power strives to right size the resources required to operate and grow in its markets and minimize the cost of those resources. Failure to do so could negatively impact culture, growth and earnings and place the Company at a competitive disadvantage.

Strategies employed for managing cost optimization and efficiency risk:

- Set performance targets and measure and report results compared with those targets. Measure performance against benchmarks.
- Develop and undertake efficiency initiatives and programs.
- Support internal resources by utilizing retention programs and assessing employee engagement with appropriate communication and follow-up.

Risks and risk management

Political

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. In December 2024, the Canadian federal government enacted the Clean Electricity Regulations (CER) to meet an objective of achieving a net-zero electricity system by 2050. The regulations establish unit-specific annual emissions limits for existing and new natural gas generation facilities. The CER encountered opposition from system operators, utilities, and provincial governments across Canada given concerns with the potential implications to reliability of their respective provincial energy system, affordability, economic growth, and the implications they could have on broader emission reduction strategies through the use of electrification. Capital Power shares these concerns. Canada also introduced amendments to Section 74.01 of the *Competition Act* to address greenwashing. The Act now targets environmental claims that promote the environmental, social, and ecological benefits of using or supplying a product if the claim is not based on an adequate and proper test. More broadly, it also targets environmental claims that promote the environmental and ecological benefits of a business or business activity that are not based on adequate and proper substantiation in accordance with an internationally recognized methodology. Both of these sections place the burden of proof on the entity making the environmental claim to demonstrate compliance with these provisions.

On January 6, 2025, Prime Minister Justin Trudeau announced his intention to resign as the Prime Minister of Canada and the leader of the ruling Liberal Party, once the party selects a replacement. This introduces the potential for increased political risk for Capital Power as this development may lead to a period of political uncertainty and potential policy shifts that could impact the regulatory environment in which the Company operates. Changes in government leadership often bring about new energy policies and priorities, which could affect the Company's strategic plans, operations, and financial performance. With a federal election expected in 2025, the Company will continue to monitor how political sentiment may change and how any possible change may impact the Company's business and operations.

In 2023, the United States Environmental Protection Agency (EPA) announced a proposed rule that aims to curb greenhouse gas emissions for coal-, gas-, and oil-fired power plants that run at least 50% of the time. The final rule, issued in May 2024, requires existing coal and new natural gas fired power plants to mitigate their carbon emissions based on a tiered system of compliance ranging from utilizing low emissions fuels for newly constructed gas turbines that run infrequently, to 90% carbon capture for newly constructed gas turbines that run frequently. The rule has faced several legal challenges in court and is expected to be overturned in 2025 by the Trump administration. Should the rule be overturned Capital Power would no longer have a regulatory requirement at the federal level to accelerate decarbonization efforts. However, decarbonization requirements at the state level would still apply.

Capital Power operates in multiple jurisdictions with each governmental body (federal, provincial, and state) developing their own net-zero frameworks, of which, many have not aligned on timing nor method. The outcome of the U.S. federal election indicates 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.

Strategies employed for managing political risk:

- Predict and identify existing, new or changed laws or regulations, or changed interpretations of such, and prepare and advocate appropriate responses or plans.
- Support the timely development of appropriate transmission capability through active relationships with all levels of government.
- Establish constructive relationships with relevant levels and branches of government, including key political advisors and influencers.
- Participation in relevant associations developing electricity markets.
- Include change-in-law provisions in material contracts where possible.
- Maintain a mix of technologies and geographies across our fleet.

Regulatory

Capital Power is required to maintain numerous licenses, permits and governmental approvals for the development, construction and operation of its projects and participation in its markets. If Capital Power fails to satisfy the conditions of these instruments, there could be an adverse impact on the effectiveness and cost of those projects or operations.

Capital Power's thermal assets consume water to generate electricity and are emitters of various air pollutants in addition to greenhouse gases, including NO_x, SO_2, mercury, carbon dioxide, and particulate matter. Accordingly, Capital Power's operations are subject to extensive electricity market and reliability rules and requirements, plus environmental laws, regulations, and guidelines relating to the generation and transmission of electricity, pollution and protection of the environment, extreme weather, health and safety, air emissions, water usage, wastewater discharges, hazardous material handling and storage, treatment and disposal of waste and other materials, remediation of sites, and land-use responsibility. These rules and regulations can impose a liability for costs to investigate or address any obligations. Compliance with new regulatory requirements may require Capital Power 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 Capital Power's business prospects, financial condition, or operations.

Risks and risk management

The Company is subject to requirements around minimizing the impact to wildlife at its wind facilities. Capital Power complies with all regulatory requirements which include completing pre-disturbance bird and bat studies and post-construction bird and bat monitoring programs. We could see a financial impact on our wind facilities, in certain jurisdictions, should they be curtailed to prevent wildlife loss or if more stringent policies and regulations are in place to protect wildlife.

The operations of the Company's wind assets are also required to follow appropriate sound level regulations and could be exposed to facility curtailment in the event of non-compliance. Capital Power complies with all applicable regulations, including completing applicable noise impact assessments.

Capital Power participates in competitive wholesale electricity markets in most of the jurisdictions in which it operates. Changes to the design of these markets, such as in Alberta and Ontario currently, could create additional opportunities for the Company, but also could adversely impact Capital Power's business. 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.

See Regulatory matters for further discussion of current regulatory items.

Strategies employed for managing regulatory risk:

- Predict and identify existing, new or changed laws or regulations, or changed interpretations of such, and prepare and advocate appropriate responses or plans.
- Comply with all applicable laws, regulations and guidelines and monitor compliance.
- Perform regulatory compliance audits and take corrective actions as necessary.
- Establish constructive relationships with relevant levels of government, agencies and stakeholders.
- Participate or monitor relevant consultation processes. Execute on-time permitting, license renewals and other activities associated with laws and regulations.
- Proactively identify environmental risks within operations, maintenance and construction activities and promote awareness throughout and at all levels of the Company.
- Monitor evolving water policy in the jurisdictions Capital Power operates, manage compliance with operating permits and legal requirements.
- Ensure that contractors align with Capital Power's environmental policies and procedures.
- Support the timely development of appropriate transmission capability through active relationships with regulators.
- Work with third parties to develop technologies and mitigations to deter wildlife at wind facilities.
- Management actively monitors emission abatement technologies and assesses opportunities to expand the Company's portfolio of technologies that may have direct application in reducing emissions in natural gas generating assets.
- Maintain a mix of technologies and geographies across our fleet.

Business resilience

Capital Power's ability to maintain safe and reliable operations can be disrupted by extreme events such as pandemics, natural disasters, extreme weather conditions, physical terrorist attacks and major accidents or events including environmental incidents. Climate change could cause an increase in the frequency and severity of extreme weather events, which could adversely impact Capital Power's current and future assets. If the Company is unable to quickly adapt to such disruptions, our people, assets, reputation, and business operations could be at risk.

Strategies employed for managing business resilience risk:

- Establish and maintain emergency and other related contingency planning measures to enable the timely response to and recovery from extreme weather and other events.
- Monitoring of conditions in our various jurisdictions and the collective experience of managing through the pandemic to maintain workplace safety through remote work capabilities.
- Regular assessment of our facilities for physical risks, including impacts resulting from extreme weather or other climate-change risks and, where beneficial, undertake physical changes at our facilities to mitigate those risks.
- Regular communication with external governmental and industry groups to share threat intelligence, trend analysis, and best practices.
- Annual testing of plans through tabletop exercises and participation in large scale, multi-industry exercises.
- Establish and maintain a physical security management program that is based on industry guidelines and best practices.
- Periodic internal audits of our facilities to ensure that physical security measures are aligned with the Company's risk profile.
- Maintain appropriate insurance coverage.
- Maintain fuel-type and geographic diversity.

Risks and risk management

Disruptive technology

Evolving technologies may result in energy efficiencies that outpace power demand projects or in advancements in the power industry. These changes may impact the competitiveness of Capital Power's fleet, and the success of our strategy (see Delivering on our strategy). Technological advancement may improve the competitiveness of alternative power technologies over time, resulting in their expanded deployment across power markets. Capital Power's facilities may face increased competition as these technologies are increasingly relied on to supply power and ancillary services in the markets we operate.

Climate change will drive significant innovation and transformation of the power sector, including energy production and consumption. Capital Power's focus on lower-carbon solutions is a key component in ensuring that the Company's business model remains flexible and resilient as technology evolves.

Strategies employed for managing disruptive technology risk:

- Capital Power's Management and Board of Directors evaluate the Company's strategy on an ongoing basis, including anticipating disruptive technologies that may create risks to or complement the Company's strategy.
- Management monitors emerging technologies with regular assessments and evaluations of economics of competing technologies.
- Management actively monitors emission abatement technologies and assesses opportunities to expand the Company's portfolio of technologies that may have direct application in reducing emissions from natural gas generating assets.
- Management continuously evaluates opportunities to enhance competitiveness of existing assets through optimization and efficiency initiatives.

Stakeholder activism

Effective community engagement and participation is an important element in Capital Power's business. Accordingly, progress in the Company's development, construction and operational activities could be impacted by stakeholder intervention and/or activism. Changes in law and regulatory requirements may also adversely impact the market dynamics for Capital Power, the participation levels of counterparties that Capital Power relies on to support its portfolio optimization strategies, and the costs associated with participating in these markets.

Strategies employed for managing stakeholder activism risk:

- Engage early, respectfully and in a timely manner with communities in an open, and transparent manner with a focus on building and operating mutually beneficial facilities.
- Provide various modes for communities and stakeholders to communicate with us and provide feedback – email, website, phone, open houses, community events (both hosting and attending), face-to-face and virtual meetings.
- Demonstrate action and follow through on our commitments – Capital Power tracks, logs, actions and provides follow up to community feedback and requests either individually or through newsletters, email and website updates.
- Demonstrate consistency of engagement and action across our assets by adhering to our internal standards and processes that provide a framework for accountability and best practices for Capital Power's stakeholder engagement processes.
- Continuous learning and process improvements with debriefs after completing significant engagement processes to leverage lessons learned for future projects.
- Build and maintain strong relationships in the communities we operate through regular and ongoing community engagement and investment.
- Identify and assess potential stakeholder priorities and concerns when screening growth opportunities.
- Maintain shareholder logs.

Reconciliation with Indigenous Peoples

Capital Power is committed to reconciliation with Indigenous Peoples and recognizes the energy expansion needs to be in partnership with Indigenous Peoples of Turtle Island, or North America.

Strategies employed for realizing opportunities from reconciliation with Indigenous Peoples:

Capital Power proudly works with Indigenous communities in Canada and the United States in terms of developing, constructing and operating our projects in a sustainable manner and has:

- Published an Indigenous Relations Policy to formalize our commitment to being an active participant in reconciliation with Indigenous Peoples.
- Developed a ReconciliAction Plan that prioritizes internal growth and awareness, relationship building and community support, as well as capacity building and economic opportunities.

Risks and risk management

Finance

Capital Power's ability to fund current and future capital requirements, along with its working capital needs, is dependent upon access to financial markets. Uncertainty and volatility in the Canadian and U.S. financial markets may adversely affect Capital Power's ability to access and arrange financing under favourable terms and conditions. Our cost of capital will also depend upon prevailing market conditions, and in the case of our sustainability-linked credit facilities, whether our annual targets for Scope 1 CO_2 emissions intensity levels are met. Our ability to access capital will also depend upon the Company's business and ESG performance as indicated by the assigned 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.

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.
- Utilize derivative and swap instruments to manage interest rate risk.

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.

Risks and risk management

Tax

Capital Power's operations are complex, and the determination of taxes involve tax interpretations, regulations and legislation that are continually evolving. Our tax filings are subject to audit by taxation authorities. While Capital Power maintains that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, Capital Power cannot guarantee that it will not have disagreements with taxation authorities with respect to its tax filings. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for taxes and Management believes that it has adequately provided for taxes as required by International Financial Reporting Standards, based on all information currently available. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in higher tax expense that could have a material effect on the Company.

Our effective tax rate can change depending on the mix of earnings from our various jurisdictions, changes in the valuation of deferred tax assets and liabilities, and on deductions and inclusions in determining taxable income that do not fluctuate with earnings. These changes could have an adverse impact on Capital Power, its shareholders, and the value of the Company's common shares.

Strategies employed for managing tax risk:

- Consult with all levels of government with respect to tax policy development and proposed legislation.
- Develop and maintain tax expertise and resources necessary, including third party advisors, in the application of tax legislation.
- Internal policies that guide the roles and responsibilities of our Tax Team.
- Comply with tax laws of jurisdictions that Capital Power operates in.

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.
- Utilize foreign currency forward contracts.
- Utilize cross-currency interest rate swap contracts.
- Contract significant purchases or borrowings in Canadian dollars.
- Utilize U.S. dollar denominated borrowings and/or tax equity debt financing to finance U.S. developments.

Reputation

Investors and other stakeholders are increasingly focused on our exposure to the impacts of climate change as well as our progress on our lower-carbon roadmap. This creates public perception or cost of capital risks related to Capital Power's portfolio which includes flexible-generation assets. The Company also considers reputation risk to be a consequence of all other risks that it faces. If a certain risk factor results in positive or negative consequences to the Company, its reputation may also be positively or negatively affected.

Strategies employed for managing reputation risk:

In part, the Company manages its reputation risk by employing appropriate risk management strategies for all identified risks.
Additional strategies include:

- Fostering a highly ethical culture.
- Compliance with all regulations.
- Transparent reporting on progress on our lower-carbon roadmap.
- Leadership compensation linked to ESG performance.
- Integration of ESG criteria in investment decisions to ensure appropriate consideration of ESG risks.
- Commitment to transparent reporting and disclosure to assist in addressing concerns and risks with investors and other stakeholders.
- Maintain regular, timely and ongoing open and transparent reporting to our investors and stakeholders about our performance, operations, developments, purpose, values and goals.
- Ongoing monitoring of the Company's social media and media presence for content and tone to promptly identify and address any reputational concerns.

Risks and risk management

General economic conditions, business environment and other risks

In addition to all the risks previously described, the Company is subject to adverse changes in its markets, general economic conditions, inflation, recession, as well as business model disruption. The Company is exposed to risks associated with weather variability, legal and arbitration proceedings, and risks that are not fully covered by various insurance policies.

Fluctuations in general economic conditions and inflationary pressures could expose Capital Power to higher operations, maintenance and labour costs, as well as higher construction costs for development projects. Inflationary pressures may also lead to a higher interest rate environment that could result in the risk of fluctuations in the Company's share price. These additional costs would be offset by higher revenues from our off-take agreements where inflation escalation clauses exist. The Company includes inflation clauses in the long-term contracts for our facilities output, whenever possible. The Company is exposed to financial loss should the inflation indices in the contracts for our facilities output not keep pace with the inflation indices in our long-term service agreements with OEM's. The Company remains focused on efficiencies and cost management of plant operation and maintenance, with prudent increases to headcount to support its growth. Impacts of a severe and prolonged economic downturn may include decreasing demand for power which may impact the Company's revenue as well as exposure to counterparty risks. Refer to Finance risk above for mitigations for counterparty credit risks.

The Company is dependent upon 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 its other 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, 2024, the Company loaned $4,596 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.

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 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 United States. 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 the year (see Significant events) 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 $346 million at December 31, 2024 ($324 million at December 31, 2023) for our generation facilities and the Genesee Mine. This is due to the obligation 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 decommissioning provisions could change depending on potential future changes in environmental regulations and cost estimates.

Capital Power has forward contracts to purchase environmental credits totalling $1,478 million and forward contracts to sell environmental credits totalling $1,059 million in future years. Included within these forward purchases and sales are net purchase amounts which will be used to comply with applicable environmental regulations and net sale amounts related to other emissions trading activities.

Regulatory matters

Canada

Federal Budget 2024

Budget 2024 was tabled on April 16, 2024, and provides an update on the status of previously announced clean energy ITCs. Bill C-59 (which includes the Carbon Capture, Utilization and Storage ITC and Clean Technology ITC) received Royal Assent on June 20, 2024. Capital Power's Halkirk 2 Wind, Goreway BESS and York Energy BESS projects are expected to be eligible for the Clean Technology ITC and an accrual of $151 million, based on the respective project-to-date spend, was recorded in 2024.

Clean Electricity Regulations (CER)

On December 17, 2024, the Government of Canada released the final version of the CER, as part of a broader suite of policies intended to meet the federal government's objective of achieving a net-zero electricity system by 2050.

Starting in 2035, the CER will apply to grid connected units that are greater than 25 MW and generate electricity using fossil fuels. The regulations set an annual emission limit (AEL) for each unit based on a prescribed emission intensity and the unit's capacity. The prescribed emission intensity will be 65 tCO_2/GWh for the period between January 1, 2035 and December 31, 2049; and 0 tCO_2/GWh thereafter, with compliance flexibility through carbon offsets permitted. The CER will grant an allowance of an additional 35 tCO_2/GWh over the prescribed emission intensity to 2050 and 42 tCO_2/GWh thereafter. The offsets must be registered within the Canadian system and issued no more than eight years prior to being remitted. The same offset can be applied to the CER and federal carbon pricing or a provincial carbon price that has cross recognition with Canadian offset credits. Additional compliance flexibility will be allowed through the banking of AEL credits for use in future years and the transfer of unused AEL credits between units operating in the same jurisdiction so long as the unit is not a coal facility or existing/planned cogeneration facility. Existing units, planned units, or units regulated under the coal-to-gas regulations will not have to comply with the AEL until the end of their prescribed life (EoPL) where the EoPL is defined as 25 years after the unit's commissioning date for existing units, 2049 for planned units, and the end of life assigned to coal-to-gas converted units under the Regulations Limiting Carbon Dioxide Emissions from Natural Gas-Fired Generation of Electricity. Planned units are defined as a unit that is commissioned between January 1, 2025 and December 31, 2034 where construction begins prior to December 31, 2027.

All of Capital Power's natural gas generation facilities in Canada, including the Genesee Generating Station, qualify as existing units under the CER. As such, each unit will be required to achieve compliance with the AEL at the end of their respective EoPL, 25 years after COD. Management continues to monitor development and assess impacts to Capital Power.

Natural Resources Canada (NRCAN) released the Clean Electricity Strategy on the same day as the CER. The strategy summarizes measures already announced including the CER and Clean Economy ITCs.

Public Consultation on Competition Act's New Greenwashing Provisions

Bill C-59 introduced amendments to Section 74.01 of the *Competition Act* (the Act) to address greenwashing. The Act now targets environmental claims that promote the environmental, social, and ecological benefits of using or supplying a product if the claim is not based on an adequate and proper test. More broadly, it also targets environmental claims that promote the environmental and ecological benefits of a business or business activity that are not based on adequate and proper substantiation in accordance with an internationally recognized methodology. Both of these sections place the burden of proof on the entity making the environmental claim to demonstrate compliance with these provisions.

On July 22, 2024, the Competition Bureau launched a public consultation on the greenwashing provisions seeking feedback from interested parties to inform its future enforcement guidance about environmental claims and implementation of the new provisions. Management submitted comments on September 27, 2024 outlining its concerns around unintended consequences as a result of the new provisions and recommendations on how to mitigate the likelihood of such consequences through guidance. Draft guidelines concerning environmental claims were issued by the Competition Bureau on December 23, 2024 for public consultation. Management submitted additional comments before the February 28, 2025 consultation deadline.

Mandatory Climate Disclosures for Federal Corporations and Made-in-Canada Sustainable Investment Guidelines

On October 9, 2024, the Government of Canada (GoC) announced its intention to amend the Canada Business Corporations Act (CBCA) to mandate climate-related financial disclosures for large, federally incorporated private companies. The federal government intends to work with provincial partners to harmonize its regulations with similar regulations imposed on public companies by securities regulators. Although Capital Power is a public company and not directly impacted, management is monitoring developments and assessing potential impacts to Capital Power's subsidiaries.

Until such time mandatory climate-related disclosures under Canada Securities Administrators ruling are finalized, we will continue to prioritize voluntary climate-related disclosures on the recommendations of the TCFD framework. To streamline our current voluntary disclosures, we have discontinued voluntary disclosures on guidance from the Global Reporting Initiative and no longer respond to climate change questionnaires from CDP (the global disclosure system for environmental impacts). Management continues to monitor developments on voluntary climate-related disclosures.

Regulatory matters

The GoC also announced a plan to deliver Made-in-Canada sustainable investment guidelines. These guidelines will be a voluntary tool for investors, lenders and other stakeholders for identifying (1) “green” activities, to be defined as low or zero-emitting activities that do not have material Scope 1 and 2 emissions, lower or zero downstream scope 3 emissions and sells into or benefits from markets that are expected to grow in the global net-zero transitions; and (2) “transition” economic activities, to be defined as decarbonizing activities that have material scope 1 and 2 emissions, including those with low or zero scope 3 emissions, that do not face immediate demand-side risk and do not create carbon lock-in and path dependency. The federal government has highlighted priority sectors, including electricity, where it will concentrate its efforts on developing eligibility criteria. Management continues to monitor developments and assess impacts should Capital Power pursue sustainable financing in the future.

Alberta

Alberta Electric System Operator Restructured Energy Market (REM)

On March 11, 2024, the Government of Alberta and the AESO announced plans to restructure the energy market (REM) to address long-term reliability, affordability, and decarbonization objectives. On July 11, 2024, the Minister of Affordability and Utilities announced policy decisions that direct the AESO’s technical design of the REM. Specifically, this includes moving forward with a day ahead market, allowing price to be determined by strategic offers of market participants, mitigating the market to limit the potential for excessive exercises of market power, a review of the price cap and floor, and market operational changes (security constrained dispatch and co-optimized dispatch, and shortened settlement intervals). The decision to maintain competitive forces in the market over introducing and relying solely on administrative pricing (which was a feature of the AESO’s initial REM proposal) is intended to maintain features of the existing pricing framework.

The AESO initiated a series of consultations on high-level design details on September 10, 2024, and published its high-level design document for written feedback on December 13, 2024. The high-level design includes the introduction of a new day-ahead energy market, a new day-ahead commitment product that is to provide a price signal for assets to commit to be available in real-time, and two new ramping products in the real-time market. The REM proposal introduces changes to the pricing framework, notably increasing the price cap from $1,000/MWh to $3,000/MWh, lowering the offer cap from $999.99/MWh to $800/MWh, introducing administrative scarcity pricing and lowering the price floor to -$100/MWh. The Government has also directed the AESO to design a congestion management mechanism that is market based and respects incumbency as part of the REM design.

On December 10, 2024, the Minister of Affordability and Utilities issued a direction letter to the AESO. In it, the AESO was directed to continue developing the detailed design of the REM in consultation with stakeholders, with a view to finalizing the REM design before the end of 2025. The Government intends to then bring forward any necessary policy tools to allow the REM rules to be enacted through legislation, not the AUC approvals process. The Government’s intent is for the rules to be enacted by the end of 2025 but not brought into effect until the REM is implemented, which is anticipated in 2027.

Management is participating in the AESO’s consultation to progress the market design and provided feedback to the AESO on its high-level design on January 17, 2025.

Interim Market Power Mitigation Rules

Two interim regulations to address Government of Alberta concerns with market power in the wholesale electricity market were announced on March 11, 2024. Details of the interim regulations are:

- The *Market Power Mitigation Regulation* sets out a secondary price cap in Alberta’s market where offers of generators with 5% or higher market share are limited once a hypothetical reference combined cycle unit reaches twice its expected fixed cost (capital recovery and fixed operating) recovery for the month. When the threshold is reached, the offer cap for affected generators will decline to the greater of $125/MWh or 25 times the natural gas price.
- The *Supply Cushion Regulation* enables the AESO to develop procedures to direct or keep on generating assets that cycle offline and cannot re-connect within an hour in the event it anticipates its supply cushion in the market to be less than 932 MW. In the event a generator is directed on, it will be compensated for its startup costs and minimum generation costs in the event the market prices do not cover the costs.

The expedited rules based on the interim regulations were approved by the AUC on June 19, 2024, and came into effect on July 1, 2024. The AUC has initiated a process to consider the AESO’s request for final approval of these rules. Management is participating in this process and expects the AUC to complete its determination in Q1 2025.

Transmission Policy Review

On October 23, 2023, the Government of Alberta released a discussion paper identifying different features of the existing transmission policy framework that are being reviewed to ensure the affordability, reliability and decarbonization of Alberta’s electricity system. Among other things, the discussion paper discusses potential changes to the current policy framework for allocating wires and ancillary services costs between different transmission users, the transmission planning framework, and provisions for intertie restoration and expansion. The Government of Alberta invited comments to inform potential next steps and what changes, if any, may be warranted and Capital Power has actively participated in the process.

Regulatory matters

On July 11, 2024, the Alberta Minister of Affordability and Utilities announced policy direction on long-standing transmission policy. On a go forward basis the policy direction is to move away from the current zero-congestion transmission planning standard to an optimally planned transmission planning standard where costs of transmission are evaluated against the benefits. For new transmission infrastructure, costs will be allocated based on cost causation principles, similarly all ancillary services costs will be allocated to those that cause the cost. This is a shift away from the load-pays policy as generators will now also incur cost should they cause them. These changes will be integrated in the AESO's market reform engagement.

On December 10, 2024 the Government of Alberta issued a direction letter to the AESO outlining further decisions on transmission policy to provide guidance to the AESO with respect to location signals, intertie expansion and line losses. To improve location signals when siting new generation, the existing Generator Unit Owner's Contribution will be replaced with a non-refundable Transmission Reinforcement Payment (TRP) whose proceeds will be used to offset transmission costs. There will be no upper limit on the TRP and will be implemented through changes to the AESO's tariff. To restore the intertie, the AESO has been directed to develop plans and file them with the AUC by December 31, 2026 to restore the Alberta-BC path to approximately 950 MW, procure and maintain high levels of ancillary services to allow full import flows, and replace the Alberta-Saskatchewan intertie which is nearing the end of its useful life – in doing so there is an expectation that the AESO will increase its path rating. Finally, the AESO is directed to replace its line loss methodology with a system-wide average starting January 1, 2027.

Alberta Utilities Commission Inquiry into the Ongoing Economic, Orderly and Efficient Development of Electricity Generation in Alberta

On August 3, 2023 the Government of Alberta announced that it had directed the AUC to pause approvals of renewable generation projects until February 29, 2024 and had also directed the AUC to initiate an inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta. The AUC was directed to provide a report to the Minister of Affordability and Utilities by March 29, 2024, with recommendations. The Inquiry was divided into two modules, with the AUC completing its first report on renewable development on January 31, 2024 and its second report on the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability on March 28, 2024.

On February 29, 2024, the Government of Alberta's pause on renewable generation facility approvals was lifted and additional clarity was provided on policies for siting renewable generation. This includes: an "agriculture first" approach to land-use where renewable projects have to demonstrate that they co-exist with agricultural use; a buffer zone for renewable development around specific viewscapes where wind projects will not be permitted and where other projects will be required to undertake a visual impact assessment; creation of standards for reclamation security; and plans for an engagement on use of Crown lands for renewable development. On December 6, 2024, the *Electric Energy Land Use and Visual Assessment Regulation* was introduced to formalize the February policy direction. This includes a map that depicts the pristine viewscapes, visual impact assessment zones and agricultural lands, and identifies specific locations where projects may not be permitted or face additional scrutiny. Amendments to the *Conservation and Reclamation Regulation* were also announced, requiring reclamation security for wind and solar operations.

Ontario

Emissions Performance Standards (EPS)

The Ontario Minister of the Environment, Conservation and Parks (MECP) amended the EPS to meet stricter benchmark criteria set by the Federal Government and to extend the program to 2030, effective January 1, 2023.

Under the EPS, the carbon price will align with the minimum Federal carbon price of $\$80/tCO_2e$ for the 2024 compliance period, increasing by $\$15/tCO_2e$ per year to $\$170/tCO_2e$ in 2030. The performance standard for generating electricity using fossil fuels declined from 0.370 tCO_2e/MWh to 0.310 tCO_2e/MWh effective 2023 and will remain at that level until 2030.

The contracts for the Company's York Energy, East Windsor and Goreway facilities have provisions that trigger amendments as a result of changes in GHG cost, the effect of which will limit the impact of changes to carbon compliance costs.

Market Renewal Program (MRP)

Ontario's MRP is a set of coordinated market and IESO system reforms intended to improve market transparency, competitiveness, and real-time unit scheduling. It will introduce Locational Marginal Pricing, market power mitigation, and a financially binding day-ahead market. MRP design work is complete and the IESO Board unanimously approved the market rule amendments associated with MRP on October 18, 2024. The IESO is targeting May 1, 2025 to transition to the new market.

Management has been actively involved in MRP stakeholder engagement sessions, working groups, and user tests in preparation for the transition to the new market. MRP will trigger amendments to the Company's generating contracts with the IESO. While the overall impact MRP will have on the Company will largely depend on these amendments, the Company, if necessary, may leverage various provisions within the contracts that are intended to protect suppliers from adverse effects resulting from market rule changes. Management continues to work with the IESO to minimize the impact MRP will have on its existing fleet.

Regulatory matters

On November 7, 2024, a consortium of market participants that owns non-quick start natural gas generating units, including the Company, submitted an application to the Ontario Energy Board (OEB) appealing the MRP market rule amendments. The application requests the OEB to review the amendments for consistency to the *Electricity Act 1998* and to determine if MRP unjustly discriminates against a class of market participants. The hearing is now underway, and the OEB is set to make a ruling by March 6, 2025.

Ontario's Affordable Energy Future: The Pressing Case for More Power

On October 22, 2024, the Ministry of Energy and Electrification released the government's vision for energy in a report titled *"Ontario's Affordable Energy Future: The Pressing Case for More Power."* The report highlights the important role electricity plays in Ontario's economy and the government's plans to address rapidly growing energy demand while keeping costs affordable. The report also articulates the important role electrification will have in reducing provincewide emissions and how critical natural gas generation is in supporting the energy transition and grid reliability.

The government's Powering Ontario Growth Plan remains at the forefront of the government's efforts to maintain a reliable, affordable, and clean energy system Act. The Powering Ontario Growth Plan was released in July 2023. The plan includes several critical initiatives like predevelopment work to site new large-scale nuclear generation at the Bruce generating facility, development of three small modular reactors at the Darlington site, advancement of large hydroelectric storage projects, optimization of hydroelectric generating assets, rollout of energy efficiency programs, and new transmission development. The plan also includes the IESO's procurements for new energy generation.

Bill 214: Affordable Energy Act

The Minister of Energy and Electrification introduced *Bill 214: the Affordable Energy Act, 2024* on October 23, 2024, and the Bill received Royal Assent on December 4, 2024. The overall purpose of the Bill is to enact certain parts of the government's energy vision into legislation. For example, the Bill expands the purpose of the *Energy Act, 1998* and the IESO to include the promotion of electrification and the facilitation of energy efficiency by using electricity to reduce Ontario's overall emissions. The Bill also creates a legislative requirement for the Ministry to carry out integrated energy plans every five years. Lastly, the Bill includes amendments to the *Ontario Energy Board Act, 1998* that will allow the Lieutenant Governor in Council to amend the distribution system code or the transmission system code on matters related to cost allocation or recovery.

Electrification and Energy Transition Panel

In 2022, the Ministry of Energy (now the Ministry of Energy and Electrification) established the Electrification and Energy Transition Panel to be a short-term advisory body to help the government prepare for the energy transition. The government released the Panel's final report in January 2024, in which they provided 29 recommendations related to governmental commitments, regulatory policies, Indigenous community relations, and stakeholder engagement. The Panel flagged the need for further policy direction for the role of natural gas within the energy transition, integrated long-term energy planning between electricity and natural gas, and a review of Ontario Energy Board activities to ensure they remain consistent with the goals of a lower-carbon energy economy. The Panel's recommendations have been foundational to many of the actions the Ministry has taken after its release including matters related to natural gas pipeline expansion, integrated planning, and the creation of an energy vision.

IESO Resource Adequacy Framework and Procurements

On August 28, 2024, the Honourable Stephen Lecce, the Minister of Energy and Electrification, announced that the government directed the IESO to target 5000 MW of new generation capacity to be procured by 2034, making it the largest competitive energy procurement in the province's history. In addition, the Minister directed the IESO to look for ways to accelerate the procurement timelines and announced that LT2 will be technology agnostic. The Minister also confirmed that LT2 participants will need to have municipal support for their projects, projects are not to be developed in speciality crop areas, and ground-mounted solar cannot be developed on prime agricultural lands. The Minister also announced that the projects located in Northern Ontario and projects with Indigenous community participation are to be prioritized.

The IESO released an updated electricity demand forecast on October 16, 2024. The forecast showed even higher annual demand growth resulting from step changes in EV manufacturing, industrial growth, and data centre interconnection requests. This new forecast projects electricity demand to increase 75% by 2050. For comparison, the IESO was projecting a 60% increase in electricity demand by 2050 in their Annual Planning Outlook (APO) that was released earlier in the year. In response to the revised outlook, the Minister yet again increased the procurement target. On December 11, 2024, the Minister directed the IESO to now procure up to 7500MW of new generating capacity by 2034. The Minister also requested the IESO to report back to the government on procurement options for long-lead energy resources like hydro generating facilities and long duration energy storage, and to provide contracting options for existing and new small scale electricity generation.

LT2 is set to launch in 2025 with separate procurement streams for capacity and energy. Subsequent procurements are expected to be held annually.

The IESO also launched their second medium-term procurement (MT2). MT2 will award flexible, 5-year contracts to successful proponents who have generating facilities coming off an IESO contract on or before April 30, 2029. In mid-January 2025, Capital Power submitted a bid for its Kingsbridge 1 Wind facility, and the IESO's announcement of the successful proponents is expected later in 2025.

Management believes Ontario's overall electricity needs and the IESO's commitment to awarding contracts through competitive procurements will continue to provide opportunities for the Company, including possible re-contracting opportunities for existing assets. Management remains involved in the IESO's engagements related to resource adequacy, the APO, and procurements.

Regulatory matters

British Columbia

BC Hydro Integrated Resource Plan (IRP)

As part of the 2021 IRP, in March 2023, BC Hydro advised the BCUC that it was working on a “Signpost” update to their 2021 IRP in response to the Government of BC’s announcements issuing an Environmental Assessment certificate for Cedar LNG, the establishment of a new energy action framework, and increasing load forecast. The Signpost update, filed with the BCUC on June 15, indicated an increase in BC Hydro’s demand forecast and also a reduction in supply expectations resulting in the need for BC Hydro to accelerate its plans to address both capacity and energy shortfalls. As a result of this, BC Hydro initiated a call for power on April 3, 2024, with initial intention of procuring 3,700 GWh of clean energy from greenfield projects that are able to achieve operations as early as fall 2028. On December 9, 2024 BC Hydro announced that they had successfully procured 5,000 GWh of wind generation. Capital Power did not participate in this procurement.

In June 2024, BC Hydro initiated consultation on its planned 2025 Integrated Resource Plan (IRP) with further consultation expected to occur into 2025. Management will continue to monitor and participate in this process as necessary.

United States

Recent Supreme Court Decisions

In July 2024, the U.S. Supreme Court overturned the *Chevron* doctrine, a framework that gave deference to federal agency expertise in making decisions where federal statutes are silent or ambiguous to certain issues. The authority to determine reasonable readings of ambiguous laws will now reside more clearly with the judicial branch of government, and future legislation will require Congress to draft much more precise legislative provisions and will narrow the traditional reliance on the subject matter expertise of the executive branch in the regulatory process. It is anticipated that this decision will influence how the courts view Clean Air Act issues as applicable to Capital Power’s thermal portfolio.

The Supreme Court also granted a preliminary injunction request against the Environmental Protection Agency’s (EPA) updated Good Neighbor Plan, which addresses interstate emissions that hurt downwind states’ ability to meet the Clean Air Act Standards for ozone. The stay signals that a majority on the U.S. Supreme Court believe that the opponents of the Good Neighbor Plan are likely to succeed on the merits of their litigation against the EPA rule. Without *Chevron*, it will be difficult for the EPA to prove they were acting within their statutory authority in updating the plan, and the Supreme Court decision eases states’ requirements to reduce NO_x emissions from covered sources, including fossil power plants. Capital Power has existing operations in 2 (Michigan and Alabama) of the 23 total Good Neighbor Plan States, and Management is working with legal counsel to determine the implications for Midland Cogeneration and Decatur in the event the Good Neighbor Plan is overturned.

U.S. Clean Air Act

On May 23, 2023, the EPA announced a proposed rule that aims to curb GHG emissions for coal-, gas-, and oil-fired power plants that run at least 50% of the time, with initial requirements for gas-fired power plants beginning as early as 2032. The original proposal would have required existing gas plants to utilize hydrogen co-firing or CCS within the next decade and the emission guidelines proposal will apply to existing natural gas power plants facilities with a 300 MW capacity or higher; however, in March 2024 the EPA announced plans to remove existing facilities from the scope of the proposed rule. A final rule was unveiled in May 2024, and covers new and modified gas- and oil-fired power plants. The final rule has been subject to several legal challenges, and the incoming Trump administration has indicated rolling back this rulemaking as a top priority in 2025. Management expects the new administration will cancel this regulation, thus removing the federal requirement for Capital Power to decarbonize future expansions to our thermal fleet.

Inflation Reduction Act (IRA)

The IRA passed by Congress and signed into law in August of 2022 puts the United States on a projected path to reduce greenhouse gas emissions 40 percent below 2005 levels in the next decade. Of the IRA’s $369 billion investment in addressing climate change, $270 billion will be delivered through tax incentives, putting Treasury and the Internal Revenue Service (IRS) at the forefront of IRA implementation.

In 2024, the Treasury Department prioritized finalizing rules for provisions that allow the transfer and direct payment of lower-carbon energy tax credits according to comments made by the assistant Treasury secretary for tax policy. Those provisions of the law are meant to extend credits to tax-exempt entities that have previously not been able to participate in the traditional tax equity market, including nonprofits and state and local governments. More than 200 entities registered to use elective pay or transferability and submitted pre-filing registrations for more than 1,600 projects in anticipation of the guidance.

Regulatory matters

In addition, Treasury issued initial guidance on the technology-neutral lower-carbon electricity production and investment credits that begin in 2025. Enacted in the IRA, the tech-neutral breaks will be available for lower-carbon energy projects that start construction in 2025. This guidance is a step towards replacing the Section 45 production tax credit (PTC) and Section 48 ITC — two breaks widely viewed as instrumental in the ongoing expansion of American solar and wind. Only certain technologies are currently eligible for the two credits: Section 45 allows wind, biomass, geothermal, solar, irrigation power, municipal solid waste, hydropower and marine energy, while Section 48 allows fuel cells, wind, waste energy, storage, biogas, microgrids and other energy properties. The new rules will offer tax credit eligibility awarded to zero-emissions energy sources, regardless of the technology. That includes fossil fuel generation, so long as it is certified as zero-emission.

The incoming Republican executive and legislative branches of the federal government are expected to roll back provisions in the IRA in some form. It is anticipated that the tech-neutral PTC and ITC tax credits are at moderate likelihood of being rolled back in 2025, though changes to the framework that offer safe harbor for projects that have already reached certain milestones is being considered. Any renewable project that is under construction – namely Nolin Hills, Greencastle, Hornet, Maple Leaf, and Bear Branch – may lose the tax credit benefits from the IRA. Management continues to monitor the state of the tax credits as federal budget conversations continue.

California Climate Disclosure Legislation

In the fourth quarter of 2023, the California legislature passed two bills that will require certain companies doing business in California to disclose their climate-related financial risks and their scope 1, 2, and 3 GHG emissions. These new laws were the first of their kind in the United States and have compliance deadlines of 2026, and 2027, respectively. The legislation requires the California Air Resources Board (CARB) to issue a formal rulemaking process prior to implementation of the laws, which is expected to occur later this year. Following the acquisition of the La Paloma Generating Plant in McKittrick, CA, Capital Power will be required to disclose climate related information in the state in accordance with these requirements. In September 2024, the state legislature passed SB 219 which grants CARB an extended deadline of six months to complete their rulemaking process for SB 253, moving the CARB rulemaking deadline from January 2025 to July 2025. An extended CARB rulemaking deadline, coupled with outstanding legal challenges that have been raised against SB 253, increase the likelihood that relevant compliance deadlines for Capital Power to report scope 1, 2, and 3 GHG emissions will be pushed out beyond current legislatively mandated deadlines. In December 2024, CARB issued a memo indicating that companies who make good faith efforts to meet the reporting requirements in 2026 will not be punished for incomplete disclosures, but the disclosure obligations will still remain in effect. Management will continue to monitor legal and legislative updates and provide guidance as needed.

The legislature also passed a law that requires companies that purchase or sell voluntary carbon offsets (VCOs) to disclose specific information on the transactions. The original bill text was relatively vague and clarifying legislative activities are currently ongoing. While the compliance deadline may shift from the statutory requirement of January 1, 2025 to June 1, 2025 or later, Capital Power publicly disclosed the necessary information in order to remain compliant with the original January deadline.

Washington State Carbon Market Legislation

In March 2024, the Washington legislature voted in favor of linking the statewide carbon trading market with California and Quebec. Further, in November 2024, voters in Washington considered a ballot initiative (Initiative 2117) that would have repealed the cap-and-invest program designed to reduce GHG emissions by 95% by 2050, if successful. The election results ultimately protected the cap-and-invest program, leaving California and Quebec to begin their own regulatory processes to determine whether to link with the Washington state market.

On January 1, 2025, SB 6058 goes into effect in Washington, making it easier to link the state market with the California and Quebec markets. Immediately, the allowance purchase limit for a covered entity or an opt-in entity will increase from 10% to 25% of the allowances offered during a single auction. There will also be a subsequent rulemaking that is expected to begin in 2025 that will determine compliance periods and potentially revise the definition of an electricity importer. Once Washington formally links with another carbon market, the legislation also has provisions that changes holding limits for general market participants. Until Washington links with another jurisdiction, general market participants (GMPs) cannot own more than 10% of the total allowances to be issued in a calendar year (“vintage-year”). After linkage, there will no longer be a vintage-year holding limit for GMPs. The Washington State Department of Ecology will also have the ability to reduce monetary penalties, or the number of penalty allowances required to be submitted for violations throughout the first compliance period or until Ecology enters into a linkage agreement, whichever is sooner. The Frederickson 1 Generating Station will likely not be financially impacted by Initiative 2117, as its carbon costs will be covered by Morgan Stanley or PSE through September 2030.

Michigan Legislation

On November 28, 2023, the Michigan Governor signed a legislative package that includes a goal of 100% lower-carbon energy in the state by 2040, and sets new renewable energy targets for Michigan state. The legislation requires Midland Cogeneration to achieve GHG emission reductions that are the functional equivalent of deploying on site Carbon Capture and Storage with a 90% capture rate at the facility. Management is working towards a plan to achieve that lower-carbon goal and it must be submitted under the legislation to the Michigan Public Service Commission by 2030.

Use of judgments and estimates

In preparing our audited consolidated financial statements, management made judgments, estimates and assumptions that affect the application of our 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.	During 2024, the Company assessed its equity-accounted investment in C2CNT for impairment and determined its carrying amount exceeded its recoverable amount. An impairment was recorded during the third quarter of 2024. No other indicators were identified during 2024 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 has been determined to be the lessee for the following: ▸ Beaufort Solar sale and leaseback agreement ▸ Various office, equipment and land leases
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. The renewable asset sell-down transaction in 2024 resulted in the loss of control of the Port Dover and Nanticoke and Quality Wind subsidiaries whereby Capital Power no longer fully consolidates these wind facilities and used the equity method in its financial statements effective the sell-down date (see Significant events).
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 Energy, 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.

Use of judgments and estimates

Judgment	**Management applies judgment to evaluate**	**Resulting conclusions**
Operating segments	Whether the Company operates in one or multiple business segments, and if the Company operates in multiple segments, how the aggregation criteria are applied to reportable segments.	The Company has aggregated its operating segments into one reportable business segment as its operating segments have similar products, production processes, types of customers, product distribution methods, regulatory environments and economic characteristics. Each operating segment is involved with the generation and sale of electricity, which includes the process of turning various fuel sources into electricity and managing the revenues and costs of such electricity, including engaging in trading activities. The Company's customers tend to be large commercial and industrial customers, independent system operators and government owned or sponsored entities. Given the similar size and credit profiles of these counterparties, they are deemed to be similar types of customers. The method of distributing electricity is the same across all facilities, and none of the Company's entities are rate-regulated.

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, 2024 and 2023 were as follows:

		December 31, 2024		December 31, 2023	
($ millions)	Fair value hierarchy level[1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	**865**	**865**	1,423	1,423
Trade and other receivables[2]	N/A	**546**	**546**	689	689
Government grant receivable[3]	Level 2	**438**	**400**	327	295
Fair value through profit or loss					
Derivative financial instruments assets[4]	See below	**601**	**601**	284	284
Fair value through other comprehensive income					
Derivative financial instruments assets[4]	See below	**55**	**55**	68	68
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	**751**	**751**	717	717
Subscription receipts	N/A	**–**	**–**	399	399
Loans and borrowings[3]	Level 2	**4,976**	**5,244**	4,716	4,690
Fair value through profit or loss					
Derivative financial instruments liabilities[4]	See below	**621**	**621**	536	536
Fair value through other comprehensive income					
Derivative financial instruments liabilities[4]	See below	**20**	**20**	64	64

[1] Fair values for Level 1 financial instruments are based on unadjusted quoted prices in active markets for identical instruments, while Level 2 fair values 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] Excludes current portion of government grant receivable.

[3] Includes current portion.

[4] Includes current and non-current portions.

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, 2024 and 2023 and used for risk management purposes were measured at fair value and consisted of the following:

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

		At December 31, 2023				
($ millions)	Fair value hierarchy level	Commodity cash flow hedges	Commodity non-hedges	Interest rate cash flow hedges	Foreign exchange cash flow hedges	Total
Derivative financial instruments assets	Level 2	26	268	42	–	336
	Level 3	–	16	–	–	16
		26	284	42	–	352
Derivative financial instruments liabilities	Level 2	(22)	(223)	(14)	(28)	(287)
	Level 3	–	(313)	–	–	(313)
		(22)	(536)	(14)	(28)	(600)
Net derivative financial instruments assets (liabilities)		4	(252)	28	(28)	(248)

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 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 mainly driven by changes in forward power and natural gas prices and their impact on the Alberta and U.S. portfolios. Unrealized and realized gains and losses from these 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, 2024, 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, 2024, 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 Committee of Sponsoring Organizations of the Treadway Commission and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

Summary of quarterly results

(GWh) **Electricity generation**	Three months ended **Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	Dec 2023	Sep 2023	Jun 2023	Mar 2023
Total generation	9,408	11,001	8,603	8,809	8,692	8,521	7,857	7,417
Alberta commercial facilities								
Genesee Generating Station[1]	2,029	2,114	2,028	2,388	2,666	2,650	2,552	2,690
Clover Bar Energy Centre	141	203	129	165	163	294	130	150
Joffre	140	164	139	215	138	110	150	154
Shepard	759	807	552	820	781	768	741	715
Halkirk 1 Wind	100	96	106	109	139	85	107	122
Clover Bar Landfill Gas	–	–	–	–	–	2	1	3
	3,169	3,384	2,954	3,697	3,887	3,909	3,681	3,834
Western Canada facilities								
Island Generation	–	300	–	34	–	–	2	–
Quality Wind	100	84	93	87	135	74	73	104
EnPower	4	5	3	6	5	4	3	4
Whitla Wind	371	234	338	325	345	222	280	384
Strathmore Solar	8	24	25	13	7	24	28	12
Clydesdale Solar	16	55	52	32	7	57	54	27
Halkirk 2 Wind[2]	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	501	702	511	497	499	381	440	531
Ontario facilities								
York Energy	5	19	12	6	4	8	3	4
East Windsor	3	5	2	12	3	5	3	1
Goreway	515	901	552	799	552	800	608	358
Kingsbridge 1	33	11	19	28	28	11	16	31
Port Dover and Nanticoke	74	37	63	82	81	41	54	87
	630	973	648	927	668	865	684	481
U.S. facilities								
Decatur Energy, Alabama	964	1,287	883	455	666	723	494	240
Arlington Valley, Arizona	1,099	832	795	840	1,067	1,007	908	513
Beaufort Solar, North Carolina	6	5	7	7	6	8	8	6
Bloom Wind, Kansas	174	137	184	174	169	107	153	186
Macho Springs Wind, New Mexico	29	19	41	41	26	21	41	44
New Frontier Wind, North Dakota	107	77	107	89	110	74	83	108
Cardinal Point Wind, Illinois	162	65	143	165	167	69	134	174
Buckthorn Wind, Texas	90	65	99	96	94	81	77	108
Midland Cogeneration, Michigan	1,295	1,436	1,444	1,298	1,333	1,276	1,154	1,192
Frederickson 1, Washington[3]	220	258	137	246	N/A	N/A	N/A	N/A
Harquahala, Arizona[4]	465	860	333	–	N/A	N/A	N/A	N/A
La Paloma, California[5]	497	901	317	277	N/A	N/A	N/A	N/A
	5,108	5,942	4,490	3,688	3,638	3,366	3,052	2,571

[1] Genesee Generating Station Repowered Units 1 and 2 simple cycle commissioned May 3, 2024 and June 28, 2024, respectively and dual cycle commissioned November 18 and December 13, 2024, respectively (see Significant events).

[2] Halkirk 2 Wind commenced partial operations in the fourth quarter of 2024 with full commercial operations expected in the first half of 2025.

[3] Frederickson 1 was acquired on December 28, 2023. Due to the proximity of the acquisition to December 31, 2023, generation for the quarter ended December 31, 2023 was immaterial.

[4] Harquahala was acquired February 16, 2024 (see Significant events).

[5] La Paloma was acquired February 9, 2024 (see Significant events).

Summary of quarterly results

	Three months ended							
(%) **Facility availability**	**Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	Dec 2023	Sep 2023	Jun 2023	Mar 2023
Total average facility availability	89	94	91	94	93	96	95	94
Alberta commercial facilities								
Genesee Generating Station[1]	78	83	96	92	96	96	96	99
Clover Bar Energy Centre	88	94	58	56	56	95	47	69
Joffre	91	100	80	100	89	76	95	96
Shepard	100	100	74	98	100	99	98	85
Halkirk 1 Wind	97	95	95	93	95	91	96	97
Clover Bar Landfill Gas	–	–	–	–	–	48	58	83
	85	89	86	90	93	95	91	93
Western Canada facilities								
Island Generation	100	100	100	100	100	100	100	100
Quality Wind	97	87	98	95	98	96	92	98
EnPower	75	100	100	85	91	91	94	73
Whitla Wind	96	96	98	95	96	94	94	98
Strathmore Solar	97	97	97	97	88	97	98	96
Clydesdale Solar	97	97	97	97	88	97	97	97
Halkirk 2 Wind[2]	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	97	96	98	97	97	97	96	98
Ontario facilities								
York Energy	95	100	100	100	100	99	89	100
East Windsor	97	93	99	99	97	95	99	99
Goreway	87	100	85	99	96	100	98	91
Kingsbridge 1	96	97	94	90	91	92	89	95
Port Dover and Nanticoke	89	97	98	98	97	95	96	96
	90	99	89	99	97	99	96	94
U.S. facilities								
Decatur Energy, Alabama	81	100	98	100	79	98	100	99
Arlington Valley, Arizona	99	97	99	82	98	100	98	81
Beaufort Solar, North Carolina	98	94	99	98	100	99	99	99
Bloom Wind, Kansas	93	92	94	98	96	91	98	97
Macho Springs Wind, New Mexico	97	95	96	96	97	96	98	99
New Frontier Wind, North Dakota	93	90	95	83	91	97	94	95
Cardinal Point Wind, Illinois	90	75	84	87	94	92	95	93
Buckthorn Wind, Texas	94	96	96	96	96	93	94	95
Midland Cogeneration, Michigan	94	95	95	93	93	97	94	95
Frederickson 1, Washington[3]	100	97	50	89	N/A	N/A	N/A	N/A
Harquahala, Arizona[4]	56	98	80	100	N/A	N/A	N/A	N/A
La Paloma, California[5]	96	94	94	95	N/A	N/A	N/A	N/A
	88	95	93	93	90	97	97	94

[1] Genesee Generating Station Repower Units 1 and 2 simple cycle commissioned May 3, 2024 and June 28, 2024, respectively and dual cycle commissioned November 18 and December 13, 2024, respectively (see Significant events).

[2] Halkirk 2 Wind commenced partial operations in the fourth quarter of 2024 with full commercial operations expected in the first half of 2025 Frederickson 1 was acquired on December 28, 2023. Due to the proximity of the acquisition to December 31, 2023, availability for the quarter ended December 31, 2023 was immaterial.

[3] Frederickson 1 was acquired on December 28, 2023. Due to the proximity of the acquisition to December 31, 2023, availability for the quarter ended December 31, 2023 was immaterial.

[4] Harquahala was acquired February 16, 2024 (see Significant events).

[5] La Paloma was acquired February 9, 2024 (see Significant events).

Summary of quarterly results

Financial results

($ millions)	Dec 2024	Sep 2024	Jun 2024	Mar 2024	Dec 2023	Sep 2023	Jun 2023	Mar 2023
	Three months ended							
Revenues and other income[1]								
Alberta commercial facilities and portfolio optimization	**445**	**440**	**408**	**593**	596	685	609	681
Western Canada facilities	**38**	**31**	**37**	**37**	47	32	32	41
Ontario facilities	**96**	**92**	**82**	**108**	93	94	90	97
U.S. facilities	**235**	**317**	**176**	**175**	123	121	103	144
Corporate[2]	**9**	**5**	**2**	**3**	27	35	35	33
Unrealized changes in fair value of commodity derivatives and emission credits	**30**	**145**	**69**	**203**	98	183	12	271
	853	**1,030**	**774**	**1,119**	984	1,150	881	1,267
Adjusted EBITDA[1,3]								
Alberta commercial facilities and portfolio optimization	**159**	**134**	**122**	**135**	169	210	166	235
Western Canada facilities	**26**	**19**	**27**	**24**	36	18	20	28
Ontario facilities[4]	**57**	**61**	**55**	**64**	60	58	60	62
U.S. facilities[4]	**149**	**238**	**157**	**112**	75	130	88	76
Corporate	**(61)**	**(51)**	**(38)**	**(56)**	(27)	(2)	(7)	–
	330	**401**	**323**	**279**	313	414	327	401

[1] Commencing in 2024, the Company reclassified the presentation of U.S. trading within Alberta portfolio optimization to the U.S. facilities category to better reflect the nature of these activities. Comparatives for revenues and other income and adjusted EBITDA were reclassified to conform to the current presentation.

[2] Revenues are offset by interplant category revenue eliminations.

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

[4] Western Canada facilities include adjusted EBITDA from the Quality Wind joint venture, Ontario facilities include adjusted EBITDA from the York Energy and Port Dover and Nanticoke Wind joint ventures and U.S. facilities include adjusted EBITDA from the Midland Cogeneration and Harquahala joint ventures.

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

Summary of quarterly results

Financial highlights

($ millions except per share amounts)	**Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	Dec 2023	Sep 2023	Jun 2023	Mar 2023
	Three months ended							
Revenues and other income	**853**	**1,030**	**774**	**1,119**	984	1,150	881	1,267
Adjusted EBITDA[1,2]	**330**	**401**	**323**	**279**	313	414	327	401
Net income	**242**	**178**	**76**	**205**	95	272	85	285
Net income attributable to shareholders of the Company	**240**	**179**	**75**	**205**	97	274	87	286
Basic earnings per share ($)	**1.76**	**1.32**	**0.51**	**1.58**	0.74	2.27	0.68	2.39
Diluted earnings per share ($)[3]	**1.75**	**1.32**	**0.51**	**1.57**	0.74	2.26	0.67	2.38
Net cash flows from (used in) operating activities	**438**	**236**	**136**	**334**	(18)	480	11	349
Adjusted funds from operations[1]	**182**	**315**	**178**	**142**	162	296	151	210
Adjusted funds from operations per share ($)[1]	**1.38**	**2.42**	**1.37**	**1.15**	1.38	2.53	1.29	1.80
Purchase of property, plant and equipment and other assets, net	**395**	**231**	**226**	**218**	244	262	131	86

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

[2] Includes adjusted EBITDA from the York Energy, Midland Cogeneration and Harquahala joint ventures. Quality Wind and Port Dover and Nanticoke Wind were partially divested on December 20, 2024, and then became joint ventures (see Significant events). Due to the proximity to December 31, 2024, adjusted EBITDA relating to the joint venture period was immaterial.

[3] Diluted earnings per share includes the impact of outstanding share purchase options.

Spot price averages	**Dec 2024**	**Sep 2024**	**Jun 2024**	**Mar 2024**	Dec 2023	Sep 2023	Jun 2023	Mar 2023
	Three months ended							
Alberta power ($ per MWh)	**52**	**55**	**45**	**99**	82	152	160	142
Alberta natural gas (AECO) ($ per GJ)	**1.45**	**0.65**	**1.14**	**1.94**	2.19	2.49	2.39	3.08
Capital Power's Alberta portfolio average realized power price ($ per MWh)	**78**	**74**	**78**	**82**	84	93	85	98

Factors impacting results for the fourth quarter of 2024

For the quarter ended December 31, 2024, Capital Power recorded AFFO of $182 million compared to $162 million for the quarter ended December 31, 2023. AFFO was higher than the corresponding period primarily due to higher adjusted EBITDA (see below) and lower current income tax due to lower overall consolidated net income before tax and higher tax deductions for certain capital projects. This was partially offset by higher overall sustaining capital expenditures. Adjusted EBITDA of $330 million for the quarter ended December 31, 2024, was moderately higher than the corresponding period in 2023 of $313 million. This was mainly a result of increased contributions from La Paloma, Harquahala and Frederickson 1 that were acquired early 2024 and late 2023, respectively, partly offset by lower generation and power prices captured by our Alberta commercial portfolio. Net income attributable to shareholders of $240 million was recorded for the quarter ended December 31, 2024 compared to net income of $97 million for the quarter ended December 31, 2023. In addition to the factors mentioned above, net income increased due to a gain on divestiture from the partial sale of Quality Wind and Port Dover and Nanticoke Wind facilities. This was partly offset by lower unrealized gains on changes in fair value of commodity derivatives, higher staff costs due to the VDP, higher foreign exchange losses due to the impact of the increasing value of the U.S. dollar on U.S. dollar loans and borrowings and other liabilities, higher net finance expense from increased loans and borrowings outstanding, and higher income tax expense due to lower overall consolidated net income before tax and higher tax deductions for certain capital projects.

Summary of quarterly results

Factors impacting results for the previous quarters

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

Third quarter of 2024 – For the quarter ended September 30, 2024, Capital Power recorded AFFO of $315 million compared to $296 million for the quarter ended September 30, 2023. AFFO was higher than the corresponding period primarily due to lower current income tax expense due to lower overall consolidated net income before tax and higher tax deductions for certain capital projects. This was partially offset by lower adjusted EBITDA (see below), and higher finance expense attributable to increased loans and borrowing outstanding due to issuances in the second half of 2023 and first half of 2024 to finance asset acquisitions. Adjusted EBITDA of $401 million for the quarter ended September 30, 2024, was lower than the corresponding period in 2023 of $414 million. The decrease was largely due to lower generation and lower power prices captured by our Alberta commercial portfolio and full recognition of the off-coal compensation from the Province of Alberta at the end of 2023. Partially offsetting these decreases were lower emissions costs from reduced intensity driven by a shift to more natural gas, and increased U.S. facility contributions from Frederickson 1, Harquahala, and La Paloma, which were acquired in December 2023 and February 2024, respectively. Net income attributable to shareholders of $179 million was recorded in the third quarter ended September 30, 2024 compared to $274 million for the quarter ended September 30, 2023. In addition to the factors mentioned above, net income decreased due to an impairment on the Company's C2CNT equity-accounted investment, higher finance expense from increased loans and borrowings outstanding, and lower unrealized gains on the fair value of commodity derivatives. These factors were partly offset by reduced depreciation from the retirement of the Genesee mine and decreased income tax expense due to lower overall consolidated net income before tax.

Second quarter of 2024 – For the quarter ended June 30, 2024, Capital Power recorded AFFO of $178 million compared to $151 million for the quarter ended June 30, 2023. AFFO was higher than the corresponding period primarily due to lower current income tax expense due to lower overall consolidated net income before tax. This was partially offset by lower adjusted EBITDA (see below), and higher finance expenses attributable to increased loans and borrowings outstanding due to issuances in the second half of 2023 to finance asset acquisitions. Adjusted EBITDA of $323 million for the quarter ended June 30, 2024, was lower than the corresponding period in 2023 of $327 million. The decrease was largely due to lower generation and lower power prices captured by our Alberta commercial portfolio and full recognition of the off-coal compensation from the Province of Alberta at the end of 2023. Partially offsetting these decreases were lower emissions costs from reduced intensity driven by a shift to more natural gas versus coal as the Genesee Generating Station facilities became 100% natural gas-fueled, increased U.S. facility contributions from Frederickson 1, Harquahala, and La Paloma, which were acquired in December 2023 and February 2024, respectively, and strong U.S. trading results. Net income attributable to shareholders of $75 million was recorded in the quarter ended June 30, 2024 compared to $87 million for the quarter ended June 30, 2023. In addition to the factors mentioned above, net income decreased due to higher net finance expense from interest on increased loans and borrowings, and losses on disposal for the discontinuation of the Genesee Generating Station CCS project, partly offset by lower losses on unrealized commodity derivatives.

First quarter of 2024 – For the quarter ended March 31, 2024, Capital Power recorded AFFO of $142 million compared to $210 million for the quarter ended March 31, 2023. AFFO was lower than the corresponding period primarily due to lower adjusted EBITDA (see below), higher sustaining capital expenditures as a result of larger outage scope and recent acquisitions, and higher preferred share dividends. This was partially offset by lower current income tax due to lower overall consolidated net income before tax. Adjusted EBITDA of $279 million for the quarter ended March 31, 2024, was lower than the corresponding period in 2023 of $401 million. The decrease was largely due to lower generation and lower power prices captured by our Alberta commercial portfolio, higher fuel costs year-over-year and full recognition of the off-coal compensation from the Province of Alberta at the end of 2023. This was partially offset by lower emissions costs due to use of more natural gas versus coal at the Genesee Generating Station and increased U.S. facility contributions from Frederickson 1, Harquahala, and La Paloma, which were acquired in December 2023 and February 2024, respectively. Net income attributable to shareholders of $205 million was recorded in the first quarter ended March 31, 2024 compared to $286 million for the quarter ended March 31, 2023 primarily due to the factors discussed above. These factors were partly offset by higher unrealized gains on Alberta power derivatives due to the impact of decreasing forward power prices on net forward sale contracts.

Fourth quarter of 2023 – For the quarter ended December 31, 2023, Capital Power recorded AFFO of $162 million compared to $140 million for the quarter ended December 31, 2022. AFFO was higher than the corresponding period primarily due to lower overall sustaining capital expenditures resulting from less outage activities, and higher adjusted EBITDA (see below). This was partially offset by higher current income tax due to higher overall consolidated net income before tax. Adjusted EBITDA of $313 million for the quarter ended December 31, 2023, was moderately higher than the corresponding period in 2022 of $303 million. The increase was mainly a result of realized gains on the Company's Alberta commercial portfolio optimization activities combined with lower emission compliance expenses driven by use of offsets inventory and the emission reductions resulting from the conversion of G3 from coal to natural gas, and lower transmission costs at the Alberta Commercial facilities which more than offset the lower power prices realized during the quarter compared to the prior period. Net income attributable to shareholders of $97 million was recorded in the quarter ended December 31, 2023 compared to a $98 million loss for the quarter ended December 31, 2022. In addition to the factors mentioned above, net income increased primarily due to unrealized gains on commodity derivatives during the 2023 period, compared to unrealized losses in the fourth quarter of 2022 most notably driven by the impact of decreasing power prices on forward sale contracts. These factors were partly offset by higher tax expense for the fourth quarter of 2024 due to higher net income before tax.

Summary of quarterly results

Third quarter of 2023 – For the quarter ended September 30, 2023, Capital Power recorded AFFO of $296 million compared to $328 million for the quarter ended September 30, 2022. AFFO was lower than the corresponding period primarily due to higher current income tax due to higher overall consolidated net income before tax, higher finance expense due to the issuance of green hybrid subordinated notes issued in the third quarter of 2022 and lower realized gains on settlement of interest rate derivatives, partially offset by lower sustaining capital expenditure as a result of less outage activities and lower preferred share dividends. Adjusted EBITDA of $414 million for the quarter ended September 30, 2023 was higher than the corresponding period in 2022 of $383 million. Results from Midland Cogeneration, which was acquired in September 2022, more than offset lower contributions from the Company's Alberta Commercial facilities and portfolio optimization due to lower realized power pricing on the portfolio combined with unfavourable fuel costs and higher emission costs due to increased compliance costs. Net income attributable to shareholders of $274 million was recorded in the third quarter ended September 30, 2023 compared to $34 million for the quarter ended September 30, 2022. In addition to the adjusted EBITDA factors mentioned above, net income increased due to higher unrealized gains on commodity derivatives most notably driven by decreasing forward Alberta power prices on net forward sale contracts along with the reversal of prior period unrealized losses on positions that settled during the period.

Second quarter of 2023 – For the quarter ended June 30, 2023, Capital Power recorded AFFO of $151 million compared to $180 million for the quarter ended June 30, 2022. AFFO was lower than the corresponding period primarily due to higher current income tax due to higher overall consolidated net income before tax, and higher sustaining capital expenditures mostly related to Genesee Generating Station sustaining capital related work. Partially offsetting these decreases was higher AFFO from joint ventures due to the acquisition of Midland Cogeneration. Adjusted EBITDA was mainly consistent with the corresponding period with results from the acquisition of Midland Cogeneration partially offset by the Company's Alberta Commercial facilities as outages at Genesee Generating Station Unit 2 during high Alberta power prices and low wind generation led to the need to procure high-priced MWhs to backstop the portfolio position. Net income attributable to shareholders of $87 million was recorded for the second quarter ended June 30, 2023 compared to $80 million for the quarter ended June 30, 2022. In addition to the factors mentioned above, favourable changes in unrealized gains on commodity derivatives and emission credits, and decreased foreign exchange losses contributed to the increase in net income attributable to shareholders. Favourable changes on commodity derivatives related most notably to the reversal of Alberta and U.S. unrealized positions that settled during the quarter as well as the impact of decreasing forward power prices on forward sale contracts associated with the Company's U.S. Wind facilities.

First quarter of 2023 – For the quarter ended March 31, 2023, Capital Power recorded AFFO of $210 million compared to $200 million for the quarter ended March 31, 2022. Contributing to the higher AFFO for the quarter ended March 31, 2023 was AFFO due to the acquisition of Midland Cogeneration and higher adjusted EBITDA from our Alberta commercial facilities mainly due to higher realized power pricing. In addition, we incurred lower sustaining capital expenditures during the quarter compared to the first quarter of 2022. These favourable impacts to AFFO were partially offset by: higher current income tax expense, lower adjusted EBITDA at Island Generation due to new EPA classification as a finance lease, and lower adjusted EBITDA from our Ontario thermal facilities due to lower dispatch from warmer temperatures and higher renewable generation during the first quarter of 2023 compared to 2022. Net income attributable to shareholders of $286 million was recorded in the quarter ended March 31, 2023 compared to net income attributable to shareholders of $122 million for the quarter ended March 31, 2022. In addition to the factors mentioned above, further contributions to the net income in the first quarter of 2023 included higher unrealized gains on commodity derivatives and emission credits most notably related to the reversal of Alberta and U.S. unrealized losses on positions that settled in the first quarter of 2023. This was partially offset by unrealized losses on natural gas derivatives due primarily to the reversal of prior period unrealized gains on positions that settled during the quarter as well as the impact of decreasing forward prices on forward purchase contracts.

Share and partnership unit information

Quarterly common share trading information

Capital Power'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 2024	**Sep 2024**	**Jun 2024**	**Mar 2024**	Dec 2023	Sep 2023	Jun 2023	Mar 2023
Share price ($/common share)								
High	**68.73**	**50.88**	**41.99**	**39.43**	39.88	42.34	46.73	46.90
Low	**49.20**	**38.33**	**33.90**	**35.55**	35.11	37.84	41.16	40.06
Close	**63.72**	**49.17**	**38.99**	**38.21**	37.84	37.92	42.10	41.64
Volume of shares traded (millions)	**38.0**	**28.3**	**33.5**	**25.9**	26.0	18.6	20.7	25.1

Outstanding share and partnership unit data

At February 21, 2025, the Company had 139.273 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares at February 21, 2025 were 140.462 million. The outstanding special limited voting share is held by EPCOR.

In 2022, Capital Power issued 350,000 Series 2022-A Class A Preferred Shares to the Computershare Trust Company of Canada, to be held in trust. These shares were cancelled in August 2024 with the removal of the provision for issuing preferred shares in the event of certain bankruptcy and related events, upon conversion of the $350 million 7.95% Fixed-to-Fixed Rate Subordinated Notes, Series 1 to Series 3 (see Significant events). At February 21, 2025, CPLP had 323.305 million general partnership units outstanding and 1,203.255 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

Additional information

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

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

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 consists of forward-looking statements including, but not limited to, statements regarding:

- our priorities and long-term strategies, including our corporate, and decarbonization strategies;
- our 2025 performance targets, including facility availability, sustaining capital expenditures, AFFO and
- adjusted EBITDA;
- future revenues, expenses, earnings, adjusted EBITDA and AFFO;
- the future pricing of electricity and market fundamentals in existing and target markets;
- our future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions;
- our projected 2025 and long-term targeted dividend growth;
- our expected 2025 common share and preferred share dividend dates;
- 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 (including Halkirk 2 Wind, the repowering of Genesee Generating Station Units 1 and 2, the upgrades at Goreway and York Energy, Goreway BESS, York Energy BESS, East Windsor expansion, Maple Leaf Solar, Bear Branch Solar and Hornet Solar), including expectations around timing, funding, project and acquisition costs, generation capacity, costs of technologies selected, environmental and sustainability benefits, and commercial and partnership arrangements;
- the financial impacts of the La Paloma and Harquahala acquisitions;
- the anticipated timing for completing the operational integration of the La Paloma acquisition;
- our 2025 estimated capital expenditures for previously announced growth projects;
- future development opportunities arising from the completion of the Genesee Generating Station project;
- our expectation around 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 targeted timeline for capital allocation that includes prioritizing the advancement of SMR and CCS technologies, and data centre co-location opportunities;
- the targeted timeline for completing the feasibility study of SMR in Alberta;
- our commitment to allocating growth capital towards low-carbon solutions;
- the ability to provide power for the growing build-out of data centres in North America including at our Genesee Generating Station site;
- the anticipated growth in North American data centre electricity consumption and total U.S. power demand;
- the ability to capitalize on our 2025 growth plans including contracting existing assets, expansion and optimization of our fleet, acquisition of incremental U.S. flexible generation capacity, and developments of renewables;
- the targeted average annual total shareholder return;
- the ability of profit-sharing arrangements to support partner communities;
- the anticipated impacts of the organizational review and anticipated benefits of the organizational review;
- the performance of future projects and the performance of such projects in comparison to the market;
- future growth and emerging opportunities in our target markets;
- the future energy needs of certain jurisdictions;
- anticipated resolution of dispute with contractor regarding construction work on the Genesee Repowering project;
- anticipated litigation in respect of Environmental Protection Agency (EPA) rules and plans and the outcome thereof;
- market and regulation designs and regulatory and legislative proposals and changes, regulatory updates and the impact thereof on the Company's core markets and business;
- 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; and
- the eligibility of certain projects for the Clean Technology ITC.

Forward-looking information

These statements are based on certain assumptions and analyses made by Capital Power considering its experience and perception of historical and future 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;
- performance;
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects;
- status and impact of policy, legislation and regulations;
- effective tax rates;
- the development and performance of technology;
- foreign exchange rates; and
- other matters discussed under the 2025 performance targets section.

Whether actual results, performance or achievements will conform to our expectations and predictions is subject to several known and unknown risks and uncertainties which could cause actual results and experience to differ materially from our expectations. Such material risks and uncertainties are:

- changes in electricity, natural gas and carbon prices in markets in which we operate and the use of derivatives;
- regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation;
- disruptions, or price volatility within our supply chains;
- generation facility availability, wind capacity factor and performance including maintenance expenditures;
- ability to fund current and future capital and working capital needs;
- acquisitions and developments including timing and costs of regulatory approvals and construction;
- changes in the availability of fuel;
- ability to realize the anticipated benefits of acquisitions;
- limitations inherent in our review of acquired assets;
- changes in general economic and competitive conditions, including inflation and recession;
- changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs; and
- risks and uncertainties discussed under the Risks and risk management section.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Capital Power does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in our expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

Assurance

KPMG have been engaged by the management of Capital Power to undertake a limited assurance engagement, in respect of the year ended December 31, 2024, on certain quantitative performance information disclosed in Capital Power's 2024 Integrated Annual Report.

Independent practitioner's limited assurance report

KPMG

INDEPENDENT PRACTITIONER'S LIMITED ASSURANCE REPORT

To the Board of Directors and Management of Capital Power Corporation:

We have undertaken a limited assurance engagement on certain performance metrics of Capital Power Corporation (the "Entity"), included in the accompanying Integrated Annual Report (the "Report"), for the year ended December 31, 2024.

The scope of our limited assurance engagement, as agreed with management, comprises the following performance metrics (collectively, the 'subject matter information') and criteria:

Subject Matter Information	Units	Criteria
Scope 1 Greenhouse Gas (GHG) emissions (MtCO2e)	17.4 MtCO2e	The World Resources Institute/World Business Council for Sustainable Developments' Greenhouse Gas Protocol - Corporate Accounting and Reporting Standard (Revised Edition) ("GHG Protocol")
Scope 1 GHG emissions intensity (tCO2e/MWh net generation)	0.41 tCO2e/MWh	GHG Protocol (numerator) and internally developed (denominator)
Total recordable injury frequency ('TRIF') (work-related recordable injuries/200,000 hours worked) for Corporate/Operations	0.53	Internally developed
% of women by employee group	Executive 50% Upper management 26% Professional 31% Support / front line 19%	Internally developed

The subject matter information is denoted by the symbol ☑ in the Report.

Other than as described in the preceding paragraph, we did not perform assurance procedures on the remaining information included in the Report, and accordingly, we do not express a conclusion on this information.

There are no mandatory requirements for the preparation or presentation of the subject matter information. As such, the Entity has applied the Greenhouse Gas Protocol - Corporate Accounting and Reporting Standard (Revised Edition) in relation to greenhouse gas emissions, and internally developed criteria for

Independent practitioner's limited assurance report

the remaining subject matter information. The criteria are further described on page 179-180 of the Report ("applicable criteria").

Management's Responsibility

Management is responsible for the preparation and presentation of the subject matter information in accordance with the applicable criteria.

Management is also responsible for such internal control as management determines necessary to enable the preparation and presentation of the subject matter information that is free from material misstatement, whether due to fraud or error. This responsibility includes determining the Entity's objectives in respect of sustainability performance and reporting, identifying stakeholders and material issues, and selecting or developing appropriate criteria.

Our Responsibility

Our responsibility is to express a limited assurance conclusion on the subject matter information based on the procedures we have performed and the evidence we have obtained. We conducted our limited assurance engagement in accordance with Canadian Standards on Assurance Engagements (CSAE) 3000, *Attestation Engagements Other than Audits or Reviews of Historical Financial Information* and CSAE 3410, *Assurance Engagements on Greenhouse Gas Statements*. These standards require that we plan and perform our engagement to obtain limited assurance about whether the subject matter information is free from material misstatement.

A limited assurance engagement involves assessing the suitability of the criteria used by the Entity in preparing the subject matter information in the circumstances of the engagement, assessing the risks of material misstatement, whether due to fraud or error, and responding to the assessed risks as necessary in the circumstances.

We exercised professional judgment and maintained professional skepticism throughout the engagement. Our procedures were designed and performed to obtain evidence that is sufficient and appropriate to provide a basis for our conclusion. In carrying out our engagement, we:

- Evaluated the suitability of the Entity's use of the criteria, as the basis for preparing the subject matter information in the circumstances;
- Through inquiries with relevant staff at the corporate and facility level, obtained an understanding of the Entity's control environment, processes and systems relevant to the preparation of the subject matter information, but did not evaluate the design of particular control activities, obtain evidence about their implementation or test their operating effectiveness;
- Inspected a limited number of items for each subject matter information and traced to or from supporting records, as appropriate;
- Performed analytical procedures by comparing the expected figures to actual figures and made inquiries of management to obtain explanations for any significant differences we identified;
- Made inquiries of management regarding key assumptions and, where relevant, completed the re-performance of key calculations on a sample basis;
- Considered the presentation and disclosure of the subject matter information.

The procedures performed in a limited assurance engagement vary in nature and timing from, and are less in extent than for, a reasonable assurance engagement. Consequently, the level of assurance obtained in

Independent practitioner's limited assurance report

a limited assurance engagement is substantially lower than the assurance that would have been obtained had a reasonable assurance engagement been performed.

Our Independence and Quality Management

We have complied with the independence and other ethical requirements of relevant rules of professional conduct/code of ethics applicable to the practice of public accounting and related to assurance engagements, issued by various professional accounting bodies, which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality, and professional behaviour.

The firm applies Canadian Standard on Quality Management 1, *Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements* which requires the firm to design, implement and operate a system of quality management, including policies or procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

Significant Inherent Limitations

Historical non-financial information, such as that contained in the Report, is subject to more inherent limitations than historical financial information, given the qualitative characteristics of the underlying subject matter and methods used for determining this information. The absence of a significant body of established practice on which to draw allows for the selection of different but acceptable evaluation techniques, which can result in materially different measurements and can impact comparability. The nature and methods used to determine such information, as described in the applicable criteria, may change over time. It is important to read the Entity's reporting methodology disclosed on page 179-180 of the Report.

Emphasis of Matter

As discussed in footnotes a and b of page 22 of the Report, the 2021, 2022, and 2023 comparative year GHG emissions – Scope 1 absolute and Scope 1 emissions intensity have been restated to reflect the structural change that resulted from the acquisitions of Frederickson 1, La Paloma, and Harquahala. Our conclusion is not modified with respect to this matter.

Other Matter

We have not been engaged to, and therefore do not, provide any assurance in respect of the restatement discussed in footnotes a and b of page 22 of the Report. Our conclusion is not modified in respect of this matter.

Conclusion

Our conclusion has been formed on the basis of, and is subject to, the matters outlined in this report. We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our conclusion.

Based on the procedures performed and evidence obtained, no matters have come to our attention to cause us to believe that the Entity's subject matter information for the year ended December 31, 2024, is not prepared, in all material respects, in accordance with the applicable criteria.

Our conclusion on the subject matter information does not extend to any other information, reports or documents that accompany, are presented with, or contain the subject matter information and our assurance report.

Restriction on Use

Our report is intended solely for use by Capital Power Corporation for the purpose(s) set out in our engagement agreement. Our report may not be suitable for any other purpose and is not intended for use

Independent practitioner's limited assurance report

or reliance by any third parties. While KPMG LLP acknowledges that disclosure of our report may be made, in full, by Capital Power Corporation in the Integrated Annual Report, KPMG LLP does not assume or accept any responsibility or liability to any third party in connection with the disclosure of our report.

KPMG LLP

Chartered Professional Accountants

Edmonton, Canada

February 25, 2025

Consolidated financial statements

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. 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 February 25, 2025. 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 International Financial Reporting 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,

SHaskins

Avik Dey
President and Chief Executive Officer

Sandra Haskins
Senior Vice President, Finance and
Chief Financial Officer

February 25, 2025

KPMG LLP
2200, 10175 – 101 Street
Edmonton, AB T5J 0H3
Canada
Telephone 780-429-7300
Fax 780-429-7379

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, 2024 and December 31, 2023
- the consolidated statements of income for the years then ended
- the consolidated statements of comprehensive 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, 2024 and December 31, 2023, its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with IFRS Accounting Standards.

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, 2024. 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 16, and Note 33 to the financial statements. The Entity has recorded derivative financial instrument assets of $136 million and liabilities of $292 million within level 3 of the fair value hierarchy at December 31, 2024. The estimate of fair value for level 3 derivative financial instruments contains significant unobservable inputs, including forward pricing and anticipated generation based on 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 internally developed model for the contracts entered in the year.
- 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.
- To assess the appropriateness of anticipated generation used in the models for assets in development, we compared the anticipated generation predicted by the models to the actual generation of a similar operating asset.

Independent auditor's report

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 the contracts entered in the year 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.

Evaluation of the acquisition-date fair value of PP&E of CXA La Paloma, LLC

Description of the matter

We draw attention to Note 2(d), Note 3 and Note 5 to the financial statements. The Entity acquired 100% of the equity interests in CXA La Paloma, LLC ("La Paloma"). The acquisition-date fair value of La Paloma's property, plant and equipment ("PP&E") was $834 million. The determination of the acquisition-date fair value of this PP&E involves significant estimates, including replacement cost estimates 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 CXA La Paloma, LLC 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 as well as functional and economic obsolescence for the acquired property, plant and equipment. Further, specialized skills and knowledge were needed to evaluate these estimates.

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 replacement cost estimates of the acquisition-date fair value of acquired property, plant and equipment by comparing the Entity's estimate to market data for comparable assets.
- Assessing the appropriateness of adjustments for physical deterioration as well as functional and economic obsolescence by comparing the Entity's estimated depreciated cost to a depreciation cost range that was independently developed using market data for comparable assets.
- Performing a physical site inspection to examine the existence of property, plant and equipment.

Assessment of joint control of the new partnerships

Description of the matter

We draw attention to Note 2(b), Note 3 and Note 4 to the financial statements. On December 20, 2024, the Entity sold a 49% ownership interest in the Port Dover and Nanticoke Wind and Quality Wind facilities. As part of the transaction, the facilities were transferred to newly formed partnerships in which the Entity retained 51% ownership interest (the "new partnerships"). The Entity determined that the transaction resulted in the Entity having joint control of the new partnerships. The assessment of control over the Entity's interest in partially owned subsidiaries is based on a review of the facts and circumstances, including key terms of the relevant agreements, and required significant management judgment.

Why the matter is a key audit matter

We identified the assessment of joint control of the new partnerships as a key audit matter. This matter represented an area of significant risk of material misstatement requiring significant auditor effort to evaluate the partner rights in the relevant agreements and the judgments applied to assess which activities most significantly impact the economic performance of the new partnerships.

How the matter was addressed in the audit

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

- We evaluated the Entity's accounting analysis of its exposure, or rights, to variable returns from its involvement with the new partnerships and whether it has power to direct the relevant activities of the new partnerships by inquiring of management about the nature of the rights conveyed and by comparing the analysis to the relevant agreements of the new partnerships.

Other Information

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

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditor's report thereon, included in a document likely to be entitled "2024 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.

We obtained the information included in Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions and the “2024 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 on 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, 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

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

Edmonton, Canada

February 25, 2025

Consolidated statements of income

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

Years ended December 31		2024		2023
Revenues	$	3,677	$	4,068
Other income (note 7)		99		214
Energy purchases and fuel		(1,787)		(2,166)
Gross margin		1,989		2,116
Other raw materials and operating charges		(209)		(159)
Staff costs and employee benefits expense (note 8)		(254)		(179)
Depreciation and amortization (note 8)		(503)		(574)
Impairment (note 9)		(27)		–
Other administrative expense		(201)		(153)
Foreign exchange loss		(29)		(6)
Operating income		766		1,045
Gain on divestiture (note 4)		309		–
Losses on disposals and other transactions (note 6)		(31)		(3)
Net finance expense (note 10)		(221)		(166)
Income from joint ventures (note 36)		76		65
Income before tax		899		941
Income tax expense (note 11)		(198)		(204)
Net income	$	701	$	737
Attributable to:				
Non-controlling interests	$	2	$	(7)
Shareholders of the Company	$	699	$	744
Earnings per share (attributable to common shareholders of the Company):				
Basic (note 12)	$	5.16	$	6.07
Diluted (note 12)	$	5.15	$	6.04

See accompanying notes to the consolidated financial statements

Consolidated statements of comprehensive income

(In millions of Canadian dollars)

Years ended December 31		**2024**		2023
Net income	**$**	**701**	$	737
Other comprehensive income (loss)				
Items that will not be reclassified to net income:				
Actuarial gains (losses) on defined benefits plans[1]		**1**		(2)
		1		(2)
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized gains on derivative instruments[2]		**81**		155
Reclassification of (gains) losses on derivative instruments to income for the year[3]		**(25)**		160
Equity-accounted investments[4]		**4**		(3)
Net investment in foreign subsidiaries:				
Unrealized gains (losses) on foreign currency translation[5]		**218**		(31)
		278		281
Total other comprehensive income, net of tax		**279**		279
Total comprehensive income	**$**	**980**	$	1,016
Attributable to:				
Non-controlling interests	**$**	**2**	$	(7)
Shareholders of the Company	**$**	**978**	$	1,023

[1] For the years ended December 31, 2024 and December 31, 2023, net of income tax of nil and income tax recoveries of $1, respectively.
[2] For the years ended December 31, 2024 and December 31, 2023, net of income tax expenses of $15 and $55, respectively.
[3] For the years ended December 31, 2024 and December 31, 2023, net of reclassifications of income tax expenses of $8 and income tax recoveries of $49, respectively.
[4] For the years ended December 31, 2024 and December 31, 2023, net of income tax expenses of $2 and income tax recoveries of $1, respectively.
[5] For the years ended December 31, 2024 and December 31, 2023, net of income tax expenses of nil.

See accompanying notes to the consolidated financial statements

Consolidated statements of financial position

(In millions of Canadian dollars)

At December 31	2024	2023
Assets		
Current assets:		
Cash and cash equivalents (note 13)	$ **865**	$ 1,423
Trade and other receivables (note 14)	**604**	747
Inventories (note 15)	**235**	309
Derivative financial instruments assets (note 16)	**244**	153
	1,948	2,632
Non-current assets:		
Other assets	**132**	110
Derivative financial instruments assets (note 16)	**412**	199
Finance lease receivable (note 17)	**13**	25
Government grants receivable (note 18)	**380**	269
Deferred tax assets (note 19)	**26**	16
Equity-accounted investments (note 36)	**1,096**	455
Right-of-use assets (note 20)	**118**	118
Intangible assets and goodwill (note 21)	**744**	775
Property, plant and equipment (note 22)	**8,061**	6,557
Total assets	$ **12,930**	$ 11,156
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 23)	$ **751**	$ 717
Subscription receipts (note 24)	**–**	399
Derivative financial instruments liabilities (note 16)	**147**	178
Loans and borrowings (note 25)	**157**	590
Deferred revenue and other liabilities (note 27)	**213**	96
Provisions (note 28)	**85**	67
	1,353	2,047
Non-current liabilities:		
Derivative financial instruments liabilities (note 16)	**494**	422
Loans and borrowings (note 25)	**4,819**	4,126
Lease liabilities (note 20)	**134**	140
Deferred revenue and other liabilities (note 27)	**323**	206
Deferred tax liabilities (note 19)	**863**	677
Provisions (note 28)	**373**	352
	7,006	5,923
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 29)	**4,301**	3,524
Deficit	**(74)**	(404)
Other reserves	**349**	70
Deficit and other reserves	**275**	(334)
	4,576	3,190
Non-controlling interests	**(5)**	(4)
Total equity	**4,571**	3,186
Total liabilities and equity	$ **12,930**	$ 11,156

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board:

Barry Perry

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 29)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity at January 1, 2024	$ 3,524	$ 48	$ 22	$ (10)	$ 10	$ (404)	$ 3,190	$ (4)	$ 3,186
Net income	–	–	–	–	–	699	699	2	701
Other comprehensive income (loss):									
Defined benefit plan actuarial gain	–	–	–	1	–	–	1	–	1
Cash flow derivative hedge gains	–	96	–	–	–	–	96	–	96
Reclassification of derivative hedge gains to net income	–	(33)	–	–	–	–	(33)	–	(33)
Equity-accounted investments	–	6	–	–	–	–	6	–	6
Unrealized gains on foreign currency translation	–	–	218	–	–	–	218	–	218
Tax on items recognized directly in equity	–	(9)	–	–	–	–	(9)	–	(9)
Other comprehensive income	$ –	$ 60	$ 218	$ 1	$ –	$ –	$ 279	$ –	$ 279
Total comprehensive income	–	60	218	1	–	699	978	2	980
Distributions to non-controlling interests	–	–	–	–	–	–	–	(3)	(3)
Common share dividends (note 29)	–	–	–	–	–	(335)	(335)	–	(335)
Preferred share dividends (note 29)	–	–	–	–	–	(31)	(31)	–	(31)
Tax on preferred share dividends (note 29)	–	–	–	–	–	(3)	(3)	–	(3)
Preferred share redemption	(150)	–	–	–	–	–	(150)	–	(150)
Issue of share capital	860	–	–	–	–	–	860	–	860
Share issue costs	(35)	–	–	–	–	–	(35)	–	(35)
Tax on share issue costs	8	–	–	–	–	–	8	–	8
Dividends reinvested	67	–	–	–	–	–	67	–	67
Share-based payments	–	–	–	–	1	–	1	–	1
Share options exercised	27	–	–	–	(1)	–	26	–	26
Equity as at 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 income and the employee benefits reserve.

See accompanying notes to the consolidated financial statements

Consolidated statements of changes in equity

(In millions of Canadian dollars)

	Share capital (note 29)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity at January 1, 2023	$ 3,498	$ (264)	$ 53	$ (8)	$ 10	$ (835)	$ 2,454	$ 6	$ 2,460
Net income	–	–	–	–	–	744	744	(7)	737
Other comprehensive income (loss):									
Defined benefit plan actuarial loss	–	–	–	(3)	–	–	(3)	–	(3)
Cash flow derivative hedge gains	–	210	–	–	–	–	210	–	210
Reclassification of derivative hedge losses to net income	–	209	–	–	–	–	209	–	209
Equity-accounted investments	–	(4)	–	–	–	–	(4)	–	(4)
Unrealized losses on foreign currency translation	–	–	(31)	–	–	–	(31)	–	(31)
Tax on items recognized directly in equity	–	(103)	–	1	–	–	(102)	–	(102)
Other comprehensive income (loss)	$ –	$ 312	$ (31)	$ (2)	$ –	$ –	$ 279	$ –	$ 279
Total comprehensive income (loss)	–	312	(31)	(2)	–	744	1,023	(7)	1,016
Distributions to non-controlling interests	–	–	–	–	–	–	–	(3)	(3)
Common share dividends (note 29)	–	–	–	–	–	(279)	(279)	–	(279)
Preferred share dividends (note 29)	–	–	–	–	–	(32)	(32)	–	(32)
Tax on preferred share dividends	–	–	–	–	–	(2)	(2)	–	(2)
Dividends reinvested	17	–	–	–	–	–	17	–	17
Share-based payments	–	–	–	–	1	–	1	–	1
Share options exercised	9	–	–	–	(1)	–	8	–	8
Equity at December 31, 2023	$ 3,524	$ 48	$ 22	$ (10)	$ 10	$ (404)	$ 3,190	$ (4)	$ 3,186

[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.

See accompanying notes to the consolidated financial statements

Consolidated statements of cash flows

(In millions of Canadian dollars)

Years ended December 31		2024		2023
Cash flows from operating activities:				
Net income	**$**	**701**	$	737
Non-cash adjustments to reconcile net income to net cash flows from operating activities:				
Impairment (note 9)		**27**		–
Depreciation and amortization (note 8)		**503**		574
Gain on divestiture (note 4)		**(309)**		–
Net finance expense (note 10)		**221**		166
Fair value changes on commodity derivative instruments and emission credits held for trading		**(238)**		(321)
Foreign exchange losses		**29**		6
Income tax expense (note 11)		**198**		204
Income from joint ventures (note 36)		**(76)**		(65)
Recognition of government grant deferred revenue		**–**		(126)
Tax-equity attributes (note 7)		**(76)**		(71)
Other items		**44**		13
Change in fair value of derivative instruments reflected as cash settlement		**13**		249
Distributions received from joint ventures (note 36)		**120**		36
Interest paid		**(163)**		(111)
Income taxes paid		**(38)**		(214)
Other cash items		**15**		(29)
Change in non-cash operating working capital (note 30)		**173**		(226)
Net cash flows from operating activities		**1,144**		822
Cash flows used in investing activities:				
Purchase of property, plant and equipment and other assets, net[1]		**(1,070)**		(723)
Business acquisition, net of acquired cash (note 5)		**(908)**		(134)
Acquisition of equity-accounted investment (note 5)		**(316)**		–
Divestiture (note 4)		**333**		–
Government grant received		**50**		50
Other cash flows from investing activities		**(5)**		–
Net cash flows used in investing activities		**(1,916)**		(807)
Cash flows from financing activities:				
Proceeds from issue of loans and borrowings (note 25)		**1,050**		1,200
Net proceeds from issuance of subscription receipts[2] (note 24)		**–**		399
Repayment of loans and borrowings		**(781)**		(145)
Issue costs on loans and borrowings		**(9)**		(6)
Repayment of lease liabilities		**(7)**		(6)
Issue of share capital (note 29)		**460**		–
Share issue costs		**(27)**		–
Proceeds from exercise of share options		**26**		8
Redemption of preferred shares (note 29)		**(150)**		–
Dividends paid (note 29)		**(280)**		(290)
Capitalized interest paid		**(56)**		(41)
Distributions to non-controlling interests		**(3)**		(3)
Other cash items		**(8)**		–
Income taxes paid on preferred share dividends		**(13)**		(13)
Net cash flows from financing activities		**202**		1,103
Foreign exchange gain (loss) on cash held in a foreign currency		**17**		(2)
Cash derecognized on loss of control of subsidiaries (note 4)		**(5)**		–
Net (decrease) increase in cash and cash equivalents		**(558)**		1,116
Cash and cash equivalents, beginning of year		**1,423**		307
Cash and cash equivalents, end of year	**$**	**865**	$	1,423

[1] Reflects total additions for the year ended December 31, 2024, reduced by $124 million for changes in non-cash investing working capital and other non-current assets (2023 – increased by $99 million), to arrive at cash additions of property, plant and equipment and other assets.

[2] Includes non-cash financing working capital of $7 million related to dividend equivalent payments.

See accompanying notes to the consolidated financial statements

Notes to the consolidated financial statements

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

1. Reporting entity:

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

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

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.

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 February 25, 2025.

(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. (2023 – 100%), 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. The non-controlling interests may be initially measured either at fair value or at the non-controlling interests’ proportionate share of the recognized amounts of the acquired business’ identifiable net assets. The choice of measurement basis is made on an acquisition-by-acquisition basis. 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. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

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:

Current accounting changes:

International Tax Reform – Pillar Two Model Rules (Amendments to IAS 12 – Income Taxes)

In June 2024, Canada enacted The Global Minimum Tax Act, which implements Canada’s Pillar Two legislation, with effect for fiscal years that begin on or after December 31, 2024. The Company is within the scope of the Pillar Two model rules as issued by the Organization for Economic Cooperation and Development (OECD) and has applied the exception to recognizing and disclosing information about deferred tax assets and liabilities related to Pillar Two income taxes, as provided in the amendments to IAS 12 – Income Taxes issued in May 2023.

The Company also adopted the following accounting amendments that were effective for our interim and annual consolidated financial statements commencing January 1, 2024. The adoption of these standards have not had a material impact on our financial results.

- Amendments to IAS 1 – Presentation of Financial Statements – Classification of Liabilities as Current or Noncurrent, clarifying the classification requirements in the standard for liabilities as current or non-current.
- Amendments to IFRS 16 – Leases – Lease Liability in a Sale and Leaseback, clarifying subsequent measurement requirements for sale and leaseback transactions for seller-lessees.
- Amendments to IAS 1 – Presentation of Financial Statements – Non-current Liabilities with Covenants, refining the 2020 amendments to IAS 1 to further clarify the classification, presentation, and disclosure requirements in the standard for non-current liabilities with covenants.
- Amendments to IAS 7 – Statement of Cash Flows and IFRS 7 – Financial Instruments: Disclosures – Supplier Finance Arrangements, adding disclosure requirements that require entities to provide qualitative and quantitative information about supplier finance arrangements. The Company participates in a supplier finance arrangement related to expenditures on Halkirk 2 Wind (note 27).

Notes to the consolidated financial statements

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

2. Material accounting policies, continued:

(c) Accounting changes, continued:

Future accounting changes:

CSDS 1 – General Requirements for Disclosure of Sustainability-related Financial Information and CSDS 2 – Climate-related Disclosures

In December 2024, the Canadian Sustainability Standards Board (CSSB) released its first two finalized Canadian Sustainability Disclosure Standards (CSDS) in an effort to support companies in identifying and reporting sustainability information that investors need for informed decision-making. The CSSB Standards will be effective for annual reporting periods beginning on or after January 1, 2025, on a voluntary basis in Canada. Climate-related disclosures will remain voluntary until incorporated into Canadian Securities Administrators ruling and become mandatory under securities legislation in Canada. Until such time, Capital Power will continue to prioritize voluntary climate-related disclosures on the recommendations of the Task Force on Climate-related Financial Disclosures framework.

The IASB has issued the following new standard and amendments to existing standards, which will take effect in future years:

- Amendments to the Classification and Measurement of Financial Instruments (Amendment to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures re: Power Purchase Agreements)

  In December, 2024, the International Accounting Standards Board (IASB) issued targeted amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures. 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. 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 to enable investors to understand the effect of these contracts on a company’s financial performance and cash flows. The amendments are effective for annual reporting periods beginning or after January 1, 2026 with early application permitted.

- 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 to IFRS 9 and IFRS 7 and IFRS 18 on the Company’s consolidated financial statements.

(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. When the excess is negative, a bargain purchase gain is recognized immediately into net income.

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. Where an acquisition involves consideration contingent on future events, any changes in the amount of consideration paid will be recognized into net income.

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. 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.

(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 and the Joint Operators’ rights to the corresponding revenues and obligations for the corresponding expenses. 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.

Notes to the consolidated financial statements

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

2. Material accounting policies, continued:

(e) Investments in joint arrangements, continued:

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 respective joint venture's total comprehensive income or loss after the date of acquisition, until the date on which significant influence ceases. 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. The translation for other non-monetary assets is not updated from historical exchange rates unless they are carried at fair value. Revenues, other income and expenses are translated at average exchange rates prevailing during the period. 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 average exchange rates prevailing during the period. 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 subsidiaries.

(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 18),
- 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 18).

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 treated and recorded within loans and borrowings, refer to note 2(j).

(h) Revenue recognition:

The Company's revenues from contracts with customers are disaggregated by major type of revenues and operational groupings by facility category. Major types of revenues include energy revenues and emission credit revenues. When multiple promises exist in a single customer contract, management exercises judgment to identify 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 as described in the following table. Disaggregated revenues are disclosed in note 39.

Notes to the consolidated financial statements

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

2. Material accounting policies, continued:

(h) Revenue recognition, continued:

Contracts with customers by operational groupings

Operational grouping	Description
Alberta Commercial	Power sold into energy markets on a merchant or non-contracted basis is included in energy revenues. Renewable Energy Credit (REC) sales from Halkirk 1 Wind are also within the scope of IFRS 15 and are described in the contracts with customers table below. The Company's portfolio optimization activities and associated revenues are excluded from the scope of IFRS 15.
Western Canada Contracted	Power generated from the Western Canada Contracted facilities is sold pursuant to long-term energy supply contracts which are included in energy revenues within the scope of IFRS 15. REC sales from a portion of Whitla 2 Wind are within the scope of IFRS 15 and are described in the contracts with customers table below. The following are excluded from the scope of IFRS 15: ▸ Energy sales from Island Generation are managed under an electricity purchase agreement that is considered a lease and accounted for under IFRS 16. ▸ VPPAs to sell renewable generation and environmental attributes from the renewable facilities are accounted for under IFRS 9.
Ontario Contracted	Power generated from the Ontario Contracted facilities is sold pursuant to long-term energy supply contracts which are included in energy revenues within the scope of IFRS 15.
U.S. Contracted	Power generated from the U.S. Contracted facilities that are managed under power purchase agreements or arrangements (PPAs) and emission credit revenues under fixed price contracts are included in energy revenues and emission credit revenues, respectively, within the scope of IFRS 15. Power generation revenues from U.S. Contracted facilities that are managed under tolling agreements are leases and accounted for under IFRS 16 and excluded from the scope of IFRS 15. Certain U.S. renewable facilities contain revenue swap arrangements that are accounted for under IFRS 9 which are also excluded from the scope of IFRS 15.

Contracts with customers

Revenue type	Description
Energy revenues	Electricity and natural gas supply contracts include a single performance obligation that is satisfied over time. Revenues from the sale of electricity and natural gas are recognized under the right to invoice practical expedient. The right to invoice practical expedient allows an entity to recognize revenue when it has the right to invoice the customer, if that amount corresponds directly with the value to the customer of the entity's performance completed to date. This occurs upon delivery or availability for delivery under the respective contracts. Customers are billed in the reporting period subsequent to when the performance obligation was met and settlements are in accordance with the agreed-upon contractual terms. 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	RECs generated by certain of the Company's facilities are sold to the respective customers under the terms of fixed price agreements. REC revenues 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.

The Company's contracts with customers are billed and paid in accordance with agreed-upon contractual terms. The Company has not incurred additional costs to obtain or fulfil the contracts with its customers.

At December 31, 2024 and 2023, the Company has not recorded any conditional unbilled receivables (contract assets) and has recorded customer advances and deposits (contract liabilities) related to certain joint operation recoveries within deferred revenue and other liabilities (note 27).

Notes to the consolidated financial statements

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

2. Material accounting policies, continued:

(h) Revenue recognition, continued:

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 Company records any gains resulting from sale and leaseback transactions as deferred revenue on its consolidated statements of financial position and amortizes the gain to depreciation and amortization on a straight-line basis over the lease term.

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.

(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.

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. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability. Lease payments are recorded as interest expense and a reduction of the lease liability. Interest expense is recognized using the effective interest method. The Company is the lessee in contracts for various office, equipment, and land leases.

Lessor

At lease inception the Company determines whether the lease transfers substantially all of the 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 unless another method better represents the earnings process.

(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. The Company may designate financial instruments as held at FVTPL when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis.

Notes to the consolidated financial statements

(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

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 fair value through income or loss 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. Liabilities are derecognized when the contractual obligations are discharged, cancelled or expired.

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.

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.

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.

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

2. Material accounting policies, continued:

(k) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rates, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, option contracts and VPPAs. Such 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. VPPAs are derivative instruments under which the Company receives the difference between fixed contracted prices per megawatt-hour (MWh) and settled market prices and provides the counterparty with a contracted amount of environmental attributes generated by the renewable facility.

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 finance expense during the periods when the variability in cash flows of the hedged items affect net income or as the original hedged item settles. 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. Unrealized gains and losses are recorded in other comprehensive income or loss. Fair values are determined in the manner described in note 3.

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. Derivative instruments are measured at FVTPL unless cash flow hedge accounting is used, in which case they are measured at FVTOCI. Embedded derivative instruments that are clearly and closely related to their host contract as noted above are never separated and are classified and measured as a combined instrument.

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 Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

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.

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.

Notes to the consolidated financial statements

(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, continued

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized in net income. 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.

(l) Property, plant and equipment

Property, plant and equipment is recorded at cost, net of accumulated depreciation and/or 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 recognized into net income 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.

(m) Intangible assets:

Capitalization

Intangible assets with definite lives are recorded at cost, net of accumulated amortization and/or accumulated impairment losses, if any. Intangible assets with definite lives are generally amortized over the related assets useful lives, as described below. Refer to note 21 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 would be 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

2. Material accounting policies, continued:

(m) Intangible assets, continued

Amortization, continued:

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.

At the end of each reporting period the Company makes an assessment as to whether there is any indication that previously incurred impairment losses no longer exist. If such an indication exists, the Company estimates the asset's recoverable amount. Any reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount or the carrying amount that would have been determined, after depreciation or amortization, had the original impairment loss not been recognized.

Any reversal is recognized into net income for the period. An impairment loss in respect of goodwill is not reversed.

Financial assets

The Company applies the expected credit loss (ECL) impairment model which applies to all financial assets. The Company considers the probability of default upon initial recognition of financial assets and whether there has been a significant increase in credit risk on an ongoing basis throughout each reporting period. The impairment methodology applied depends on whether there has been a significant increase in credit risk. The Company applies judgment to assess whether there is a significant increase in credit risk and considers available and reasonable forward-looking information in supporting this assessment.

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.

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, 2024. Credit risk management procedures, including risk mitigation practices, are as described in note 34.

Notes to the consolidated financial statements

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

2. Material accounting policies, continued:

(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), or in loans and borrowings.

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 Company's operations are complex, and the related domestic and foreign tax interpretations, regulations, legislation, and jurisprudence are continually changing. 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 uncertainty related to income taxes, if any. It is measured using tax rates enacted or substantively enacted at the reporting date. There are usually some tax matters in question that result in uncertain tax positions. 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. Current income tax assets and liabilities are only offset if certain criteria are met.

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. Deferred income tax assets and liabilities are offset only 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.

(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.

Notes to the consolidated financial statements

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

2. Material accounting policies, continued:

(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 benefits 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 as a 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 operates an equity-settled, share-based compensation plan where each stock option converts into one common share. The fair value of options granted for employee services is recognized over a three-year vesting period as a compensation expense within staff costs and employee benefits expense and credited to the employee benefits reserve. The employee benefits reserve is reduced as the options are exercised and the amount initially recorded as a credit in employee benefits reserve is reclassified to share capital. The total amount to be expensed over the vesting period is determined by reference to the fair value of the options granted.

The Company determines the fair value of stock options 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 Plan, RSU Plan and the DSU Plan, 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 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, 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

(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 an arrangement 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 20.

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 36.

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. The equity method of accounting is being applied to Capital Power's 51% ownership interest in Capital Power's Port Dover and Nanticoke Wind and Quality Wind facilities resulting from the December 20, 2024 divestiture to Axium Infrastructure (Axium), described in note 4. The equity method has been applied based on Management's assessment of the contractual rights which indicate that the new partnerships are jointly controlled by the Company and Axium.

Operating segments

As noted in note 39, the Company operates in one reportable business segment. The Company has aggregated its operating segments into one reportable business segment as its operating segments have similar products, production processes, types of customers, product distribution methods, regulatory environments and economic characteristics. Each operating segment is involved with the generation and sale of electricity, which includes the process of turning various fuel sources into electricity and managing the revenues and costs of such electricity, including engaging in trading activities. The Company's customers tend to be large industrial and commercial customers, independent system operators and government owned or sponsored entities. Given the similar size and credit profiles of these counterparties, they are deemed to be similar types of customers. The method of distributing electricity is the same across all facilities, and none of the Company's entities are rate-regulated.

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 could be agreed on between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statements of financial position, 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

(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 derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels.

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 5 – Business acquisitions;
- Notes 16 and 33 – Financial instruments;
- Note 22 – Property, plant and equipment; and
- Note 28 – Provisions

Depreciation and amortization

Depreciation and amortization allocate the cost of assets and their components over their estimated useful lives on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of the life characteristics of common assets. During 2024 and 2023, management assessed the major components of existing and acquired property, plant and equipment in the respective years (see note 5) 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

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 19.

4. Divestiture:

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. At December 31, 2024, transaction fees of $7 million have been recorded within trade and other payables.

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 (see note 36).

4. Divestiture, continued:

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.

5. Business acquisitions:

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.

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

Notes to the consolidated financial statements

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

5. Business acquisitions, continued:

Acquisition of CXA La Paloma, LLC, continued:

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, for the year ended December 31, 2024, 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.

Acquisition of Frederickson 1 Generating Station

On December 28, 2023, the Company acquired a 50.15% ownership interest in the Frederickson 1 Generating Station (Frederickson 1) joint operation with Puget Sound Energy for $134 million (US$102 million) including working capital adjustments.

Frederickson 1 is a 265 MW natural gas-fired combined-cycle generating facility located in Pierce County, Washington that operates under long-term contracts out to October 2030 with credit-worthy counterparties. Capital Power financed the transaction using cash on hand and its credit facilities.

The Frederickson 1 acquisition supports the Company's growth strategy and increases the Company's geographical diversification and contracted cash flows.

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

		December 28, 2023
Trade and other receivables	$	3
Inventories		2
Property, plant and equipment		104
Intangible assets		32
Trade and other payables		(1)
Provisions		(6)
Fair value of net assets acquired	$	134

The results of operations of Frederickson 1 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. Due to the proximity of the close of the acquisition to December 31, 2023, revenues and net income of less than $1 million (US$1 million) are included in the consolidated statement of income for the year ended December 31, 2023.

Had the acquisition occurred at January 1, 2023, the combined entity of the Company and the Frederickson 1 facility would have had a total of $4,089 million of revenues, $219 million of other income and $753 million of net income for the year ended December 31, 2023.

In conjunction with the acquisition of Frederickson 1, for the year ended December 31, 2023, the Company incurred $3 million (US$2 million) in acquisition costs which have been recorded on the Company's consolidated statements of income as other administrative expenses.

6. Losses on disposals and other transactions:

Year ended December 31		**2024**		2023
Net losses related to decommissioning of facilities	**$**	**(11)**	$	(1)
Termination fee[1]		**(18)**		–
Other		**(2)**		(2)
Total losses on disposals and other transactions	**$**	**(31)**	$	(3)

[1] Termination fee of $18 million related to the discontinuation of the Genesee carbon capture and storage project related to termination of sequestration hub evaluation work.

Notes to the consolidated financial statements

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

7. Other income:

Year ended December 31	2024	2023
Contributions and grants	$ 6	$ 6
Government compensation (note 18)	–	126
Production tax credits	76	71
Other	17	11
Other income	$ 99	$ 214

8. Expenses:

Year ended December 31	2024	2023
Included in staff costs and employee benefits expense		
Share-based payments (note 32)	$ 41	$ 12
Post-employment defined contribution plan expense	8	8
Post-employment defined benefit plan expense	2	3
	51	23
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 22)	400	489
Amortization of intangible assets (note 21)	93	74
Depreciation of right-of-use assets (note 20)	10	10
Depreciation of other assets	–	1
	$ 503	$ 574

9. Impairment:

In the third quarter of 2024, management made the strategic decision to redirect resources from the Company's C2CNT equity-accounted investment (note 36) 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.

10. Net finance expense:

Year ended December 31	2024	2023
Interest expense		
Interest on loans and borrowings	$ 270	$ 195
Capitalized interest	(56)	(41)
Total interest expense	214	154
Other finance expense		
Accretion on decommissioning provisions (note 28)	12	11
Interest on lease liabilities	9	9
Accretion on deferred government grant revenue	–	9
Interest on long-term government grants receivable	(9)	(11)
Other	(5)	(6)
Net finance expense	$ 221	$ 166

Notes to the consolidated financial statements

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

11. Income tax expense:

Year ended December 31	2024	2023
Current income tax		
Current income tax expense	$ 36	$ 156
Adjustments for prior periods	(5)	(1)
Total current income tax expense	31	155
Deferred income tax		
Origination and reversal of temporary differences	176	57
Recognition of previously unrecognized tax benefits	(9)	(8)
Total deferred income tax recovery	167	49
Income tax expense	$ 198	$ 204

Reconciliation of effective income tax rate

Year ended December 31	2024	2023
Income before tax	$ 899	$ 941
Income tax at the statutory rate of 23%	207	216
Increase (decrease) resulting from:		
Amounts attributable to non controlling interests, equity-accounted investments and tax-equity interests	(12)	(9)
Change in unrecognized tax benefits	(9)	(8)
Non-taxable amounts	(5)	–
Statutory and other rate differences	20	5
Other	(3)	–
Income tax expense	$ 198	$ 204

Global minimum top-up tax

The Pillar Two legislation requires the ultimate parent entity of a group to pay top-up tax, on a jurisdiction-by-jurisdiction basis, on profits of its subsidiaries that are taxed below 15%. The Company has assessed its potential exposure based on the most recent available information and determined that the transitional safe harbour provided for in the new Pillar Two model rules applies in the jurisdictions where it operates. As a result, there is no Pillar Two current tax impact for the year ended December 31, 2024. While there may be risk that the impact of the global minimum tax could eventually result in an increase to the Company's overall effective tax rate, the global minimum top-up tax is not currently anticipated to have a significant impact on the financial position of the Company.

Notes to the consolidated financial statements

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

12. Earnings per share:

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

Year ended December 31		2024		2023
Income for the period attributable to shareholders	**$**	**699**	$	744
Preferred share dividends[1]		**(34)**		(34)
Earnings available to common shareholders	**$**	**665**	$	710
Weighted average number of common shares		**128,902,973**		117,057,180
Basic earnings per share	**$**	**5.16**	$	6.07
Weighted average number of common shares		**128,902,973**		117,057,180
Effect of dilutive share purchase options		**322,450**		399,814
Diluted weighted average number of common shares		**129,225,423**		117,456,994
Diluted earnings per share	**$**	**5.15**	$	6.04

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

13. Cash and cash equivalents:

At December 31		2024		2023
Cash on deposit	**$**	**792**	$	1,415
Cash equivalents		**73**		8
	$	**865**	$	1,423

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 $14 million (2023 – $17 million). At December 31, 2023, this includes $400 million in subscription receipts, net of issue costs of $8 million (note 24).
- 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, 2024, cash and cash equivalents include $69 million (2023 – negative $10 million within trade and other payables) related to margin posted with exchange counterparties as a result of the Company's commodity trading activity.

14. Trade and other receivables:

At December 31		2024		2023
Accrued revenues	**$**	**292**	$	281
Trade receivables		**109**		281
Net trade receivables		**401**		562
Government grants receivable (note 18)		**58**		58
Income taxes recoverable		**97**		78
Prepayments		**36**		40
Finance lease receivable (note 17)		**12**		9
	$	**604**	$	747

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 34.

Notes to the consolidated financial statements

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

15. Inventories:

At December 31	2024	2023
Parts and other consumables	$ 117	$ 106
Emission credits	114	180
Fuel	4	23
	$ 235	$ 309

Inventories expensed upon usage for the year ended December 31, 2024 of $35 million (2023 – $116 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 16.

There were inventory write-downs of $1 million recognized in the year ended December 31, 2024 related to the end of Genesee's coal operations (2023 – $1 million). There were no reversals of previous write-downs recognized and no inventories pledged as security for liabilities in the year ended December 31, 2024 (2023 – nil).

16. Derivative financial instruments and hedge accounting:

Derivative instruments assets and liabilities are primarily used for risk management purposes as described in note 34 and consist of the following:

	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[1]		197				
Gigajoules of natural gas basis swaps[1]		63				
Metric tonnes of emission allowances		10				
Number of renewable energy credits		(11)				
Interest rate swaps			$ 800	$ 94		
Forward currency buys (U.S. dollars)					$ 84	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 22.0	0.1 to 2.1	0.2 to 1.0	0.1 to 0.6	

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

Notes to the consolidated financial statements

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

16. Derivative financial instruments and hedge accounting, continued:

	December 31, 2023					
	Energy and emission allowances		Interest rate	Foreign exchange		
	cash flow hedges	non-hedges	cash flow hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:						
Current	$ 10	$ 103	$ 40	$ –	$ –	$ 153
Non–current	16	181	2	–	–	199
Derivative instruments liabilities:						
Current	(18)	(130)	(2)	(28)	–	(178)
Non–current	(4)	(406)	(12)	–	–	(422)
Net fair value	$ 4	$ (252)	$ 28	$ (28)	$ –	$ (248)
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(5)	(34)				
Gigajoules of natural gas purchased[2]		93				
Gigajoules of natural gas basis swaps[2]		88				
Metric tonnes of emission allowances		1				
Number of renewable energy credits		(9)				
Interest rate swaps			$ 1,256			
Forward currency buys (sells) (U.S. dollars)				$ 886	$ (57)	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 23.1	0.4 to 3.1	0.2 to 0.9	0.1	

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

Fair values of derivative instruments are determined, 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, quoted Canadian dollar swap 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, 2024 and 2023, 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

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

16. 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 were:

	2024		2023	
	Unrealized gains (losses)	**Realized gains (losses)**	Unrealized gain (losses)	Realized (losses) gains
Energy cash flow hedges	**$ 38**	**$ 19**	$ 464	$ (223)
Energy and emission allowances non-hedges	**263**	**165**	308	(78)
Interest rate cash flow hedges	**(10)**	**14**	(16)	14
Interest rate non-hedges	**–**	**–**	(14)	20
Foreign exchange cash flow hedges	**35**	**–**	(29)	–
Foreign exchange non-hedges	**–**	**(5)**	–	–

The following realized and unrealized gains and losses on derivative financial instruments are included in the Company's statements of income for the years ended December 31, 2024 and 2023:

	2024	2023
Revenues	**$ 826**	$ 279
Energy purchases and fuel	**(379)**	(272)
Foreign exchange loss	**(5)**	–
Net finance expense	**14**	20

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices, interest rate risk relating to future borrowings and foreign exchange risk relating to future capital investment in U.S. dollars. For the year ended December 31, 2024, the amount realized within net finance expense pertaining to the ineffective portion of hedging derivatives was nil (2023 – nil).

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

At December 31	**2024**
Within one year	**$ 42**
Between one and five years	**57**
After five years	**17**
	$ 116

17. Finance lease receivable:

Finance income of $10 million was recognized in revenues for the year ended December 31, 2024 (2023 – $12 million).

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

	December 31, 2024	December 31, 2023
Amounts receivable under finance lease:		
Less than one year	**$ 17**	$ 18
Between one and five years	**14**	32
Total undiscounted lease receivable	**31**	50
Unearned finance income	**(6)**	(16)
Net investment in lease	**25**	34
Less: current portion[1]	**(12)**	(9)
	$ 13	$ 25

[1] Included within trade and other receivables.

18. 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 ITC pertaining to the Halkirk 2 Wind, York Energy BESS and Goreway BESS projects. As a result, the Company accrued $151 million for the year ended December 31, 2024, to government grants receivable 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. The Company is working closely with all relevant project contractors and taking all reasonable efforts to ensure these requirements are met.

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.

The GoA conducted an audit on the calculation of net book values driving the compensation payments and has withheld approximately $2.7 million from each of the payments from 2017 through 2024. The Company is disputing the withholding but has reduced the amounts recorded related to the compensation stream to reflect the uncertainty around the withheld portion of the payments (reduction of $1.5 million to the government compensation amount recorded in other income for each of the corresponding years from 2017 through 2024). The respective deferred revenue and government grant receivable amounts were likewise adjusted to reflect total payments over the 14-year term of $712 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 invest with the repowering of Genesee 1 and 2 and other renewable projects under construction (see note 37(a)). 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 has achieved its off-coal milestone with the commercial operations of the Genesee Repowering project in 2024, ahead of the required 2030 phase-out.

Notes to the consolidated financial statements

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

19. Deferred tax:

Movement of deferred tax balances

	At January 1, 2024	Recognized in net income	Currency translation adjustment	Recognized directly in other comprehensive income	Amounts relating to acquisition	Recognized directly in equity	At December 31, 2024	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 57	$ (48)	$ 2	$ –	$ –	$ –	$ 11	$ 11	$ –
Property, plant and equipment	(755)	(197)	(20)	–	(5)	–	(977)	–	(977)
Intangible assets	(43)	14	2	–	(8)	–	(35)	21	(56)
Deferred partnership (income) losses	(58)	108	–	–	–	–	50	50	–
Derivative financial instruments	52	(51)	4	(7)	–	–	(2)	176	(178)
Share issue costs and deferred financing charges	1	–	–	–	–	6	7	7	–
Equity-accounted investments	8	(58)	1	(2)	–	–	(51)	7	(58)
Deferred revenue and other liabilities	37	48	2	–	–	–	87	87	–
Right-of-use assets	(26)	1	(1)	–	2	–	(24)	–	(24)
Finance lease receivable	(8)	2	–	–	–	–	(6)	–	(6)
Government grants receivable	(77)	10	–	–	–	–	(67)	–	(67)
Decommissioning provisions	78	(4)	1	–	10	–	85	85	–
Goodwill	13	(1)	1	–	–	–	13	13	–
Prepaid reclamation amounts	(11)	3	–	–	–	–	(8)	–	(8)
Other provisions	18	4	–	–	–	–	22	22	–
Other assets[1]	13	(6)	–	–	–	–	7	10	(3)
Other liabilities[2]	3	9	–	–	–	–	12	15	(3)
Lease liabilities	37	(1)	2	–	1	–	39	39	–
Deferred tax (liabilities) assets	$ (661)	$ (167)	$ (6)	$ (9)	$ –	$ 6	$ (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, and other assets.

[2] Includes trade and other payables and loans and borrowings.

Notes to the consolidated financial statements

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

19. Deferred tax, continued:

Movement of deferred tax balances, continued

	At January 1, 2023	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to acquisition	Recognized directly in equity	At December 31, 2023	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 61	$ (4)	$ –	$ –	$ –	$ 57	$ 57	$ –
Property, plant and equipment	(779)	24	–	–	–	(755)	–	(755)
Intangible assets	(49)	8	–	(2)	–	(43)	18	(61)
Deferred partnership (income) losses	(63)	5	–	–	–	(58)	–	(58)
Derivative financial instruments	238	(83)	(103)	–	–	52	151	(99)
Share issue costs and deferred financing charges	3	(1)	–	–	(1)	1	1	–
Equity-accounted investments	(4)	11	1	–	–	8	17	(9)
Deferred revenue and other liabilities	66	(29)	–	–	–	37	37	–
Right-of-use assets	(28)	2	–	–	–	(26)	–	(26)
Finance lease receivable	(9)	1	–	–	–	(8)	–	(8)
Government grants receivable	(86)	9	–	–	–	(77)	–	(77)
Decommissioning provisions	67	9	–	2	–	78	78	–
Goodwill	7	6	–	–	–	13	13	–
Prepaid reclamation amounts	(12)	1	–	–	–	(11)	–	(11)
Other provisions	18	(1)	1	–	–	18	18	–
Other assets[3]	13	–	–	–	–	13	14	(1)
Other liabilities[4]	9	(6)	–	–	–	3	5	(2)
Lease liabilities	38	(1)	–	–	–	37	37	–
Deferred tax (liabilities) assets	$ (510)	$ (49)	$ (101)	$ –	$ (1)	$ (661)	$ 446	$ (1,107)
Set-off of tax						–	(430)	430
Net deferred tax (liabilities) assets						$ (661)	$ 16	$ (677)

[3] Includes inventories, trade and other receivables, and other assets.
[4] Includes trade and other payables and loans and borrowings.

Unrecognized deferred tax assets

Deferred tax assets have not been recognized on the following items:

At December 31	**2024**	2023
Non-capital losses	**$ –**	$ 17
Deductible temporary differences with no expiry	**–**	69
	$ –	$ 86

Tax losses carried forward

	2024		2023	
	Tax losses	**Expiry dates**	Tax losses	Expiry dates
Unrecognized tax losses carried forward	**$ –**	**not applicable**	$ 17	2032-2033

At December 31, 2024, the Company has non-capital losses carried forward of $48 million (2023 – $270 million), of which $41 million (US$28 million) (2023 – $264 million (US$200 million)) relates to U.S. subsidiaries. The Company determined that it is probable that there is sufficient future taxable income that would be available to utilize the recognized non-capital losses carried forward.

Notes to the consolidated financial statements

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

20. Leases:

Lessee – right-of-use assets

	Land	Offices	Equipment	Total
At January 1, 2023	$ 83	$ 18	$ 26	$ 127
Additions	2	3	–	5
Other adjustments	(1)	(1)	–	(2)
Depreciation	(4)	(3)	(3)	(10)
Foreign currency translation adjustments	(1)	–	(1)	(2)
At December 31, 2023	$ 79	$ 17	$ 22	$ 118
Additions	**5**	**6**	**–**	**11**
Depreciation	**(4)**	**(3)**	**(3)**	**(10)**
Divestiture (note 4)	**(6)**	**–**	**–**	**(6)**
Foreign currency translation adjustments	**4**	**1**	**–**	**5**
At December 31, 2024	**$ 78**	**$ 21**	**$ 19**	**$ 118**

Lessee – lease liabilities

The following table presents amounts recognized in the consolidated statements of income:

At December 31,	**2024**	2023
Income from rental and sub-leasing	**$ 1**	$ 1
Interest on lease liabilities	**(9)**	(9)
Variable lease payments not included in the measurement of lease liabilities	**(6)**	(5)

At December 31, 2024, expenses related to short-term and low-value leases was nil (2023 – nil).

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, 2024, the cost of such property, plant and equipment was $1,048 million (December 31, 2023 – $928 million), less accumulated depreciation of $322 million (December 31, 2023 – $244 million).

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

At December 31	**2024**
2025	**$ 119**
2026	**135**
2027	**141**
2028	**141**
2029	**141**
Thereafter	**344**
Total	**$ 1,021**

Notes to the consolidated financial statements

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

21. Intangible assets and goodwill:

	Intangible work in progress	PPAs	Contract rights	Other rights	Emission credits	Software	Goodwill	Total
Cost								
At January 1, 2023	$ 41	$ 605	$ 87	$ 170	$ 182	$ 55	$ 35	$ 1,175
Additions	73	–	–	–	36	–	–	109
Additions into service	(3)	–	2	(2)	–	3	–	–
Retirements and other disposals	–	(53)	–	1	(58)	–	–	(110)
Acquisition of Fredrickson 1 (note 5)	–	32	–	–	–	–	–	32
Transfers to held for sale emission credits inventories	–	–	–	–	(51)	–	–	(51)
Other	–	(1)	(1)	(2)	–	–	–	(4)
At December 31, 2023	$ 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 of La Paloma (note 5)	–	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
Accumulated amortization								
At January 1, 2023	$ –	$ (264)	$ (27)	$ (32)	$ –	$ (35)	$ –	$ (358)
Amortization (note 8)	–	(61)	(4)	(5)	–	(4)	–	(74)
Retirements and other disposals	–	53	–	–	–	–	–	53
Other	–	2	–	1	–	–	–	3
At December 31, 2023	$ –	$ (270)	$ (31)	$ (36)	$ –	$ (39)	$ –	$ (376)
Amortization (note 8)	–	(76)	(4)	(8)	–	(5)	–	(93)
Other	–	(5)	(1)	(1)	–	–	–	(7)
At December 31, 2024	$ –	$ (351)	$ (36)	$ (45)	$ –	$ (44)	$ –	$ (476)
Net book value								
At January 1, 2023	$ 41	$ 341	$ 60	$ 138	$ 182	$ 20	$ 35	$ 817
At December 31, 2023	$ 111	$ 313	$ 57	$ 131	$ 109	$ 19	$ 35	$ 775
At December 31, 2024	$ 10	$ 337	$ 57	$ 242	$ 45	$ 18	$ 35	$ 744

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 for both the 2024 and 2023 annual impairment tests. As such, no impairments were required for the East Windsor CGU.

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2024 and 2023.

Restrictions on assets

There are no charges over the Company's intangible assets.

Notes to the consolidated financial statements

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

22. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
At January 1, 2023	$ 719	$ 147	$ 8,007	$ 8,873
Additions	585	–	25	610
Additions into service	(93)	–	93	–
Retirements and other disposals	(2)	–	(17)	(19)
Acquisition of Fredrickson 1 (note 5)	–	–	104	104
Revisions to decommissioning costs (note 28)	–	–	13	13
Other	(1)	–	–	(1)
Foreign currency translation adjustments	(2)	–	(43)	(45)
At December 31, 2023	$ 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 of La Paloma (note 5)	**11**	**18**	**805**	**834**
Divestiture (note 4)	**(1)**	**(1)**	**(725)**	**(727)**
Revisions to decommissioning costs (note 28)	**–**	**–**	**(25)**	**(25)**
Foreign currency translation adjustments	**8**	**–**	**233**	**241**
At December 31, 2024	**$ 863**	**$ 166**	**$ 9,483**	**$ 10,512**
Accumulated depreciation				
At January 1, 2023	$ –	$ –	$ (2,513)	$ (2,513)
Depreciation (note 8)	–	–	(489)	(489)
Retirements and other disposals	–	–	15	15
Foreign currency translation adjustments	–	–	9	9
At December 31, 2023	$ –	$ –	$ (2,978)	$ (2,978)
Depreciation (note 8)	**–**	**–**	**(400)**	**(400)**
Retirements and other disposals	**–**	**–**	**602**	**602**
Divestiture (note 4)	**–**	**–**	**370**	**370**
Foreign currency translation adjustments	**–**	**–**	**(45)**	**(45)**
At December 31, 2024	**$ –**	**$ –**	**$ (2,451)**	**$ (2,451)**
Net book value				
At January 1, 2023	$ 719	$ 147	$ 5,494	$ 6,360
At December 31, 2023	$ 1,206	$ 147	$ 5,204	$ 6,557
At December 31, 2024	**$ 863**	**$ 166**	**$ 7,032**	**$ 8,061**

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are provided in note 10. The average borrowing rate used to capitalize interest during the year was 5.4% (2023 – 5.1%) for projects financed using general borrowings. For the years ended December 31, 2024 and 2023, 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 25.

Notes to the consolidated financial statements

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

23. Trade and other payables:

At December 31	2024	2023
Operating accruals[1,2]	$ 427	$ 420
Trade payables	163	183
Dividends payable	91	72
Accrued interest	70	41
Taxes payable	–	1
	$ 751	$ 717

[1] At December 31, 2024, the brokerage margin accounts are in a positive position of $69 million and included within cash and cash equivalents (note 13). At December 31, 2023, includes $10 million related to the liability position of brokerage margin accounts.

[2] 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 a total cost of $49 million of which $39 million is recorded within operating accruals and $10 million within provisions. The total restructuring costs are expected to be paid within the next six months as the impacted employees will depart the Company by June 2025.

24. Subscription receipt offering:

In relation to the La Paloma and Harquahala acquisitions (note 5), the Company completed a bought deal financing in 2023, of 8,231,000 subscription receipts (the Subscription Receipts), at an issue price of $36.45 per Subscription Receipt (Offering Price), for gross proceeds of $300 million less issue costs of $6 million.

Additionally, the Company issued, 2,745,000 Subscription Receipts at the Offering Price to Alberta Investment Management Corporation (AIMCo) on a private placement basis (Private Placement), for gross proceeds of approximately $100 million less issue costs of $2 million.

While the Subscription Receipts remained outstanding, holders were entitled to receive cash payments (Dividend Equivalent Payments) per Subscription Receipt equal to dividends declared by Capital Power on each Common Share. At December 31, 2023, Dividend Equivalent Payments of $7 million were recorded within net finance expense on the consolidated statements of income.

The La Paloma Acquisition closed on February 9, 2024 and each Subscription Receipt was automatically exchanged in accordance with their terms for one common share of Capital Power. The Harquahala Acquisition closed on February 16, 2024.

Notes to the consolidated financial statements

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

25. Loans and borrowings:

	Effective interest rate	December 31, 2024	December 31, 2023
Unsecured senior medium-term notes, payable semi-annually			
Issued by CPC, at 4.28% due in 2024	4.37%	$ –	$ 450
Issued by CPC, at 4.99% due in 2026	5.07%	300	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	–
Issued by CPC, at 3.15% due in 2032	3.21%	350	350
Issued by CPC, at 5.97% due in 2034	6.05%	450	450
		2,725	2,575
CPC private placement, payable semi-annually			
Issued by CPC, at 3.85% due in 2026	3.85%	160	160
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%	216	199
Issued by CPC, at 4.96% due in 2034	5.02%	50	50
		701	684
CPLP unsecured senior notes, payable semi-annually			
US$65, at 5.61% due in 2026	5.67%	93	86
		93	86
Subordinated notes, payable semi-annually			
Issued by CPC, at 8.13%, due in 2054	8.21%	450	–
Issued by CPC, at 7.95%, due in 2082	8.08%	350	350
		800	350
CPLP non-recourse financing, payable quarterly			
Goreway Power Station, $564 at floating rates, due in 2027	5.63%	330	372
East Windsor Cogeneration Project, at 6.28%, due in 2029	6.23%	71	82
Macho Springs, US$50 at 6.90%, due in 2031	7.00%	35	38
		436	492
Tax-equity financing, payable quarterly[1]			
Bloom Wind, US$37		53	71
New Frontier Wind, US$29		42	51
Cardinal Point Wind, US$74		107	112
Buckthorn Wind, US$38		55	61
Committed credit facilities			
CPLP US$201, at floating rates, repaid in 2024[2]	6.40%	–	266
		257	561
Total debt payable		5,012	4,748
Less: current portion		157	590
		4,855	4,158
Less: deferred debt issue costs		36	32
		$ 4,819	$ 4,126

[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%.

[2] At December 31, 2023, CPLP US$201 million, at floating rates, due in 2028 with an effective interest rate of 9.20%.

Notes to the consolidated financial statements

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

25. Loans and borrowings, continued:

$850 million medium-term notes

On December 15, 2023, the Company closed a public offering of unsecured medium-term notes in the aggregate principal amount of $850 million (the Offering). The Offering consists of $400 million medium-term notes with a coupon rate of 5.378% and $450 million of medium-term notes with a coupon rate of 5.973% which mature on January 25, 2027 and January 25, 2034, respectively.

$350 million medium-term note

On September 15, 2023, the Company closed a public offering of unsecured medium-term notes in the aggregate principal amount of $350 million. The notes have a coupon rate of 5.816% and mature on September 15, 2028.

$350 million subordinated notes, Series 1 exchange

On August 15, 2024, the Company announced the approval of amendments to the indenture governing the $350 million 7.95% fixed-to-fixed rate subordinated notes, Series 1, due September 9, 2082 (Series 1 Notes). These changes allowed for the exchange of all outstanding Series 1 Notes for an equal amount of new 7.95% fixed-to-fixed rate subordinated notes, Series 3, due September 9, 2082 (Series 3 Notes). This note exchange was completed on August 15, 2024, following the execution of the necessary supplemental indentures. The Series 3 Notes share the same economic terms as the Series 1 Notes, including interest rates and maturity dates with the provision for delivery of preferred shares upon the occurrence of certain bankruptcy and related events being removed from terms governing the Series 3 Notes. Accordingly, the 350,000 Series 2022-A Class A Preferred Shares previously issued in connection with Series 1 Notes to Computershare Trust Company of Canada, to be held in trust as treasury shares to satisfy Capital Power's obligations under the indenture governing the Series 1 subordinated notes were cancelled.

$600 million medium-term notes

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 $120 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 $50 million.

Goreway financing represents the asset level debt assumed on acquisition. The debt is secured by a charge against the assets of the facility which have a carrying amount of $564 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

The Company's sustainability-linked credit facilities (SLCs) are committed to July 2029 and include $1 billion of unsecured credit facilities, comprised of a $700 million syndicated credit facility and an unsecured club credit facility of $300 million. At December 31, 2024, the Company had Canadian loans of nil (2023 – nil), U.S. loans of nil (2023 – $266 million (US$201 million)) and letters of credit of nil (2023 – nil) outstanding under these facilities.

Bilateral unsecured demand credit facilities are available to Capital Power and include $1,421 million for the issuance of letters of credit and a further $25 million in general facilities. The general facilities are undrawn at December 31, 2024 and 2023 while letters of credit of $608 million (2023 – $559 million) have been issued as described in note 38.

Notes to the consolidated financial statements

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

25. Loans and borrowings, continued:

Committed credit facilities, continued

Under the terms of the unsecured credit facilities, 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 applicable bankers' acceptance rate plus a spread ranging from 1.2% to 2.5%, depending on the Company's credit rating.

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, 2024, $99 million of bonds were issued under these facilities (2023 – $77 million).

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

	2024	2023
Loans and borrowings[1]		
At January 1	**$ 4,716**	$ 3,726
Changes from financing cash flows:		
Proceeds from issue of loans and borrowings (note 25)	**1,050**	1,200
Repayments	**(781)**	(145)
Deferred debt issue costs	**(9)**	(6)
Total changes from financing cash flows	**260**	1,049
Effect of changes in foreign exchange rates	**51**	(14)
Non-cash repayments on tax-equity financing	**(76)**	(71)
Implicit interest on tax-equity financing	**19**	23
Other non-cash items	**6**	3
Total other changes	**–**	(59)
At December 31	**$ 4,976**	$ 4,716

[1] Includes deferred debt issue costs.

	2024	2023
Lease liabilities[2]		
At January 1	**$ 147**	$ 153
Changes from financing cash flows:		
Repayments	**(7)**	(6)
Total changes from financing cash flows	**(7)**	(6)
Additions	**6**	5
Additions through business acquisitions (note 5)	**5**	–
Divestiture (note 4)	**(6)**	–
Other adjustments	**–**	(3)
Effects of changes in foreign exchange rates	**6**	(2)
Total other changes	**11**	–
At December 31	**$ 151**	$ 147

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

Notes to the consolidated financial statements

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

27. Deferred revenue and other liabilities:

At December 31		2024		2023
Deferred payments on capital project costs	$	**290**	$	209
Contract liabilities[1]		**33**		37
Other deferred revenue and liabilities		**213**		56
		536		302
Less current portions:				
Contract liabilities[1]		**4**		5
Deferred payments on capital project costs		**48**		45
Deferred payments on capital project costs – supplier finance arrangement[2]		**130**		21
Other deferred revenue and liabilities		**31**		25
Total current deferred revenue and other liabilities		**213**		96
	$	**323**	$	206

[1] During the year ended December 31, 2024 $3 million (2023 – $13 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 at a later date.

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, 2024 and 2023. The Company does not have any supplier finance agreements presented within trade and other payables.

28. Provisions:

		Decommissioning		Employee benefits[1]		Total
At January 1, 2024	$	**324**	$	**95**	$	**419**
Additional liabilities incurred		**41**		**53**		**94**
Liabilities assumed in business acquisition (note 5)		**32**		**–**		**32**
Liabilities settled		**(31)**		**(36)**		**(67)**
Foreign currency translation adjustments		**7**		**–**		**7**
Divestiture (note 4)		**(14)**		**–**		**(14)**
Revisions to decommissioning costs (note 22)		**(25)**		**–**		**(25)**
Accretion (note 10)		**12**		**–**		**12**
At December 31, 2024	$	**346**	$	**112**	$	**458**
Non-current		**310**		**63**		**373**
Current		**36**		**49**		**85**
	$	**346**	$	**112**	$	**458**

[1] Included in the employee benefits provision is $54 million pertaining to the share-based payment obligations described in note 32, of which $15 million is vested at December 31, 2024 (2023 – $31 million total share-based payment obligation, $11 million vested).

Notes to the consolidated financial statements

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

28. Provisions, continued:

Decommissioning provisions

The Company has recorded decommissioning provisions for its power generation facilities and the Genesee coal mine (the Genesee Mine) as it is obliged 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, 2024, the Company's estimate of the undiscounted cash flow required to settle its decommissioning obligations is approximately $717 million (2023 – $616 million), calculated using an inflation rate of 2% (2023 – 2%). The expected timing for settlement of the obligations is between 2025 and 2060, 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 2060 for the power generation facilities. The payments to settle the obligations are expected to occur between 2025 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 2.94% to 4.86%. The actual timing and net costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

No assets have been legally restricted for settlement of these liabilities.

29. Share capital:

Authorized shares

	Number of shares authorized[1]
Common shares	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 share	one

[1] In August, 2024, when Series 1 Notes were exchanged for Series 3 Notes (note 25), the 350,000 Series 2022-A Class A Preferred Shares were cancelled.
Capital Power previously issued these Series 2022-A Class A Preferred Shares to Computershare Trust Company of Canada, in connection with the Company's offering of the Series 1 Subordinated Notes in 2022. The Series 2022-A Class A Preferred Shares were held in trust as treasury shares to satisfy Capital Power's obligations under the indenture governing the Series 1 Subordinated Notes. Dividends were not payable on the 2022-A Class A Preferred Shares, nor did any dividends accumulate or accrue prior to cancellation of the Series 2022-A Class A Preferred Shares.

Notes to the consolidated financial statements

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

29. Share capital, continued:

Issued and fully paid shares

	Common shares			Preference shares		
	Number of shares		Amount	Number of shares		Amount
At January 1, 2023	116,886,649	$	2,895	25,000,000	$	603
Share purchase options exercised (note 32)	314,663		9	–		–
Dividend reinvestment plan[2]	481,309		17	–		–
At December 31, 2023	117,682,621	$	2,921	25,000,000	$	603
Shares issued[3]	**18,796,000**		**860**	**–**		**–**
Share issue costs[3]	**–**		**(35)**	**–**		**–**
Deferred taxes on share issue costs	**–**		**8**	**–**		**–**
Share purchase options exercised (note 32)	**827,930**		**27**	**–**		**–**
Dividend reinvestment plan[2]	**1,672,877**		**67**	**–**		**–**
Preferred share redemption[4]	**–**		**–**	**(6,000,000)**		**(150)**
At December 31, 2024	**138,979,428**	**$**	**3,848**	**19,000,000**	**$**	**453**

[2] Effective for the September 30, 2023 dividend, the Company reinstated its dividend re-investment plan for its common shares.

[3] In relation to the La Paloma and Harquahala acquisitions (note 5):

- The Company completed a public and private subscription receipt offering in the fourth quarter of 2023, and in February 2024, upon closing of the La Paloma acquisition, each subscription receipt was automatically exchanged in accordance with their terms for one common share of Capital Power.
- The public offering of 8,231,000 common shares was issued at an issue price of $36.45 per common share (Offering Price) for total gross proceeds of $300 million less issue costs of $12 million. The private offering of 2,745,000 common shares was issued at the Offering Price to AIMCo on a private placement basis, for gross proceeds of $100 million less issue costs of $4 million.

In December 2024, the Company completed a public offering of 7,820,000 common shares at an issue price of $58.80 per common share for total gross proceeds of $460 million less issue costs of $19 million.

[4] 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 Company's shares are subject to a Shareholder Rights Plan (Rights Plan). The objective of the Rights Plan is to ensure, to the extent possible, the fair treatment of all shareholders in connection with any take-over bid for the securities of the Company, and to provide the Board with sufficient time to evaluate unsolicited take-over bids and to explore and develop alternatives to maximize shareholder value. The Rights Plan will continue in force until the end of the annual meeting of shareholders in 2025, at which time the Company expects to extend the Rights Plan for an additional 3 years, subject to Board of Directors and shareholder approval and subject to any changes in applicable securities law requirements.

Cumulative rate reset preference shares

Preferred shares[5]	Dividend per share per annum[6]	Dividend rate reset[7]	Redemption and Conversion option date[8,9]	Right to convert into[9]
Series 1	$0.655	Reset to $0.655 from $0.765 per annum effective December 31, 2020 for the March 31, 2021 dividend payment.	December 31, 2025	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
Series 11	$1.438	Dividend rate reset will not be applied as Series 11 Shares were redeemed in 2024.	Redeemed on June 30, 2024	No longer applicable

[5] Redemption – Series 11 Shares were redeemed on June 30, 2024 and dividend rate reset and conversion options are no longer applicable.

[6] Dividend rate per annum – Holders of Series 1, Series 3, Series 5, and Series 11 shares will be entitled to receive fixed cumulative quarterly dividends that yield 2.62%, 6.86%, 6.63%, and 5.75% (effective until Series 11 shares were redeemed on June 30, 2024) 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.

[7] 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.

[8] 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.

[9] 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.

Notes to the consolidated financial statements

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

29. Share capital, continued:

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			
	2024		2023		**2024**		2023	
	Per share	**Total**	Per share	Total	**Per share**	**Total**	Per share	Total
Common[10,11]	**$ 2.5338**	**$ 335**	$ 2.390	$ 279	**$ 2.4969**	**$ 316**	$ 2.355	$ 275
Preference:								
Series 1	**0.6553**	**3**	0.6553	3	**0.6553**	**3**	0.6553	3
Series 3	**1.7151**	**11**	1.3633	8	**1.7151**	**11**	1.3633	8
Series 5	**1.6577**	**13**	1.4836	13	**1.6577**	**13**	1.4836	13
Series 11[12]	**0.7188**	**4**	1.4375	8	**0.7188**	**4**	1.4375	8

[10] On July 30, 2024, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares to $0.6519 per common share effective for the third quarter of 2024.

[11] For the year ended December 31, 2024, dividends paid on common shares consist of $249 million (2023 – $258 million) paid in cash and $67 million (2023 – $17 million) paid through the Company's dividend re-investment plan as common shares.

[12] The quarterly dividend for the second quarter of 2024 was the final quarterly dividend on the Series 11 shares and, as the Redemption Date is also the dividend payment date, the Redemption Price will not include the quarterly dividend for the second quarter of 2024. Instead, the quarterly dividend for the second quarter of 2024 was paid on the redemption date separately to shareholders of record as of June 17, 2024.

In 2024 and 2023, the Company did not purchase and cancel any of its outstanding common shares under its Toronto Stock Exchange approved normal course issuer bid (NCIB). The most recent NCIB expired on March 2, 2024.

30. Change in non-cash operating working capital:

Year ended December 31	**2024**	2023
Trade and other receivables	**$ 194**	$ 275
Inventories	**77**	(4)
Trade and other payables	**(58)**	(470)
Deferred revenue and other liabilities	**(5)**	(4)
Provisions	**(35)**	(23)
	$ 173	$ (226)

31. Related party balances and transactions:

Nature of transactions

As described in note 36, 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.

Compensation of key management personnel

Year ended December 31	**2024**	2023
Short-term employee benefits	**$ 8**	$ 11
Share-based payments	**11**	13
	$ 19	$ 24

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

Notes to the consolidated financial statements

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

32. 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 may be exercised within 7 years of the grant date.

The following illustrates share purchase options activity during the years ended December 31, 2024 and 2023:

	2024			2023		
	Number of options		**Weighted average exercise price**	Number of options		Weighted average exercise price
Options outstanding, at January 1	**1,736,821**	**$**	**33.78**	1,710,709	$	30.56
Granted	**384,021**		**37.81**	399,911		42.45
Exercised[1]	**(827,930)**		**29.40**	(314,663)		25.91
Forfeited	**(37,296)**		**39.79**	(55,079)		40.92
Expired	**(35,354)**		**40.36**	(4,057)		42.45
Options outstanding, at December 31	**1,220,262**	**$**	**37.65**	1,736,821	$	33.78
Vested options outstanding, at December 31	**550,958**	**$**	**35.21**	1,062,752	$	29.46

[1] The weighted average share price at the date of exercise was $47.19 (2023 – $40.22).

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

	Share purchase options issued in:			
		2024		2023
Share price at grant date	**$**	**37.81**	$	41.41
Weighted average fair values at grant date	**$**	**3.32**	$	4.38
Expected volatility		**17.40%**		18.40%
Expected option life		**4.5 years**		4.5 years
Expected dividend yield		**6.506%**		5.603%
Risk-free interest rate		**3.12%**		3.36%
Exercise price	**$**	**37.81**	$	41.41
Expiry date		**March 15, 2031**		March 11, 2030

During the year ended December 31, 2024, the Company recorded compensation expense of $1 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2023 – $1 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options at December 31, 2024 is 4.55 years (2023 – 3.76 years). The exercise prices of share purchase options outstanding at December 31, 2024 range from $24.47 to $42.45 (2023 – $17.33 to $42.45).

Notes to the consolidated financial statements

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

32. Share-based payments, continued:

Performance share units

Capital Power grants 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 Environmental, Social and Governance metrics, weighted at 20%.

	2024	2023
PSUs outstanding, at January 1	**328,926**	439,157
Granted[2]	**125,729**	140,990
Released[3]	**(201,519)**	(271,116)
Dividends reinvested	**21,383**	19,641
Added by Performance Factor	**96,432**	31,427
Forfeited	**(18,520)**	(31,173)
PSUs outstanding, at December 31	**352,431**	328,926

[2] The fair value of the PSUs at the grant date was $37.47 (2023 – $42.26).

[3] The weighted average share price at the date of release was $37.71 (2023 – $46.30).

During the year ended December 31, 2024, the Company recorded a compensation expense of $21 million (2023 – $6 million) related to the outstanding PSUs in staff costs and employee benefits expense.

Restricted share units

Capital Power grants 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.

	2024	2023
RSUs outstanding, at January 1	**285,934**	282,928
Granted[4]	**108,484**	125,230
Released[5]	**(98,288)**	(124,289)
Dividends reinvested	**18,385**	14,099
Forfeited	**(21,419)**	(12,034)
RSUs outstanding, at December 31	**293,096**	285,934

[4] The fair value of the RSUs at the grant date was $37.47 (2023 – $42.26).

[5] The weighted average share price at the date of release was $38.18 (2023 – $46.58).

During the year ended December 31, 2024, the Company recorded a compensation expense of $9 million (2023 – $4 million) related to the outstanding RSUs in staff costs and employee benefits expense.

Deferred share units

The Company has approved a 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 of 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. During the year ended December 31, 2024, the Company recorded a compensation expense of $10 million (2023 – $1 million) related to the outstanding DSUs in staff costs and employee benefits expense.

Notes to the consolidated financial statements

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

33. Financial instruments:

Fair values

The Company classifies and measures its cash and cash equivalents, trade and other receivables, subscription receipts 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.

Details of the Company's derivative instruments are described in note 16.

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

		December 31, 2024		December 31, 2023	
	Fair value hierarchy level	**Carrying amount**	**Fair value**	Carrying amount	Fair value
Financial assets[1]					
Government grants receivable (note 18)	Level 2	**$ 438**	**$ 400**	$ 327	$ 295
Financial liabilities[1]					
Loans and borrowings (note 25)	Level 2	**$ 4,976**	**$ 5,244**	$ 4,716	$ 4,690

[1] Includes current portion.

Fair value hierarchy

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

	December 31, 2023			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ –	$ 336	$ 16	$ 352
Derivative financial instruments liabilities	–	(287)	(313)	(600)

Valuation techniques used in determination of fair values within Level 3

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

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

The Company has a 20-year revenue offtake swap agreement for Buckthorn Wind expiring in 2038, where the market price is swapped for a fixed price per unit of actual generation. The notional quantities are not set forth in the contract. In the prior year, observable forward market pricing was only available for the next 12 years, leading the Company to develop a generation forecast for the remainder of the contract and a price forecast for the 2 years for which forward market prices were not available. These were both significant inputs to the determination of fair value, therefore this financial instrument was classified as Level 3. In the current year, forward market pricing is available for the entire duration of the contract, and as such, we no longer use a price forecast. The Level 3 determination is now solely based on the generation forecast.

Notes to the consolidated financial statements

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

33. Financial instruments, continued:

Fair value hierarchy, continued

Valuation techniques used in determination of fair values within Level 3, continued

The Company has a 10-year VPPA for Whitla Wind, two 15-year fixed-price contracts for Clydesdale Solar, a 15-year VPPA for Halkirk 2 Wind and a 25-year fixed-price contract for Strathmore Solar, expiring in 2032, 2037, 2039 and 2047, respectively, to generate renewable generation and deliver environmental attributes. Observable forward market prices are not available for the full terms of the contracts and notional quantities used to calculate fair value reflect anticipated generation, therefore pricing and generation forecasts have been developed based on internal modelling. Accordingly, these financial instruments are classified as Level 3.

In addition, at December 31, 2024 and December 31, 2023, the Company holds contracts for the sale of RECs for which pricing beyond two years is not readily observable and the contracts are therefore classified in Level 3 of the hierarchy.

The Company has a 2-year commodity swap agreement expiring in 2026, where the hourly market price is swapped for a fixed price per unit of actual electricity load consumed by the counterparty's customers. The notional quantities are not set forth in the contract, and as such the Company has developed a load forecast for the remainder of the contract, making it appropriate to classify the deal as Level 3.

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

At December 31	**2024**	2023
REC pricing (per certificate) – Solar	**$3 to $201**	$3 to $204
REC pricing (per certificate) – Wind	**$3 to $8**	$3 to $7
Forward power pricing (per MWh) – Solar	**$15 to $113**	$34 to $194
Forward power pricing (per MWh) – Wind	**$15 to $142**	$22 to $136
Average monthly generation (MWh) – Strathmore Solar	**6,554**	6,671
Average monthly generation (MWh) – Clydesdale Solar	**26,088**	11,162
Average monthly generation (MWh) – Whitla Wind	**46,256**	39,123
Average monthly generation (MWh) – Bloom Wind	**60,060**	59,471
Average monthly generation (MWh) – Buckthorn Wind	**16,540**	17,620
Average monthly generation (MWh) – Halkirk 2 Wind	**37,760**	–

Valuation process applied to Level 3

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

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

At December 31	**2024**	2023
REC pricing – Solar	**$ 2**	$ 1
REC pricing – Wind	**4**	3
Forward power pricing – Solar	**4**	19
Forward power pricing – Wind	**59**	71
Generation – Solar	**4**	5
Generation – Wind	**13**	18

Continuity of Level 3 balances

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

Notes to the consolidated financial statements

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

33. Financial instruments, continued:

Fair value hierarchy, continued

Continuity of Level 3 balances, continued

The following table summarizes the changes in the fair value of financial instruments classified in Level 3:

		2024		2023
At January 1[2]	**$**	**(297)**	$	(456)
Additions		**27**		–
Unrealized and realized gains included in net income[3]		**137**		40
Settlements[4]		**(15)**		114
Transfers[5]		**1**		(2)
Foreign exchange gains		**(9)**		7
At December 31	**$**	**(156)**	$	(297)
Total unrealized and realized gains for the period included in net income [3]	**$**	**137**	$	40

[2] The fair value of derivative instruments assets and liabilities are presented on a net basis.
[3] Recorded in revenues.
[4] Relates to settlement of financial derivative instruments.
[5] Relates to transfers from Level 3 to Level 2 when pricing inputs became readily observable.

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

Financial assets

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, 2024 and 2023.

Financial liabilities

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, 2024 and 2023. 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.

Offsetting of financial assets and liabilities

The Company's commodity trading transactions are typically transacted on an exchange or under International Swap Dealers Association 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 on the Company's statements of financial position. In certain circumstances, including when a credit event such as a default occurs, generally all outstanding transactions under the agreement are terminated, the termination value is assessed and only a single net amount is payable by one party to the other in settlement of all transactions. Amounts that may only be offset in these circumstances do not meet the criteria for offsetting on the Company's statements of financial position.

The Company also has an agreement in place with one of its energy trading counterparties that conveys to the counterparty the right to set-off amounts receivable and amounts payable between the Company and the counterparty in certain circumstances, including when a credit event such as a default occurs on the part of the Company. Such amounts do not meet the criteria for offsetting on 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.

Notes to the consolidated financial statements

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

33. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

Financial assets subject to offsetting, enforceable master netting arrangements or similar arrangements

Types of financial assets	Gross amounts of recognized financial assets	Gross amounts of recognized financial liabilities offset in the statement of financial position	Net amounts of financial assets presented in the statement of financial position[6]	Related amounts not offset in the statement of financial position: Financial instruments	Related amounts not offset in the statement of financial position: Collateral received[7]	Net amount
At December 31, 2024						
Commodity trading assets	**$ 1,006**	**$ (241)**	**$ 765**	**$ (216)**	**$ (49)**	**$ 500**
At December 31, 2023						
Commodity trading assets	$ 601	$ (109)	$ 492	$ (121)	$ (10)	$ 361

[6] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $236 million, non-current derivative instruments assets of $410 million and trade and other receivables of $119 million (December 31, 2023 – current derivative instruments assets of $113 million, non-current derivative instruments assets of $197 million and trade and other receivables of $182 million).

[7] Collateral received relating to the net financial assets disclosed above is in the form of letters of credit received from the Company's counterparties.

Financial liabilities subject to offsetting, enforceable master netting arrangements or similar arrangements

Types of financial liabilities	Gross amounts of recognized financial liabilities	Gross amounts of recognized financial assets offset in the statement of financial position	Net amounts of financial liabilities presented in the statement of financial position[8]	Related amounts not offset in the statement of financial position: Financial instruments	Related amounts not offset in the statement of financial position: Collateral pledged	Net amount
At December 31, 2024						
Commodity trading liabilities	**$ 909**	**$ (241)**	**$ 668**	**$ (217)**	**$ (83)**	**$ 368**
At December 31, 2023						
Commodity trading liabilities	$ 704	$ (109)	$ 595	$ (123)	$ (92)	$ 380

[8] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $140 million, non-current derivative instruments liabilities of $485 million and trade and other payables of $43 million (December 31, 2023 – current derivative instruments liabilities of $148 million, non-current derivative instruments liabilities of $410 million and trade and other payables of $37 million).

34. 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 risk which includes, 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 the 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 the volatility in income and cash flow.

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 a financial risk management policy 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.

Notes to the consolidated financial statements

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

34. Risk management, continued:

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.

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 fair value of the Company's energy related derivatives are presented below by operational groupings with further details disclosed in note 16.

	December 31, 2024		December 31, 2023	
Operational grouping[1]	**Cash flow hedges**	**Non-hedges**	Cash flow hedges	Non-hedges
Alberta commercial facilities	**$ 41**	**$ 91**	$ 4	$ 31
Western Canada facilities	**–**	**62**	–	(71)
U.S. facilities	**–**	**(179)**	–	(222)
Other	**–**	**6**	–	10
	$ 41	**$ (20)**	$ 4	$ (252)

1 Geographic facility categories are aligned with how management views the business and depict the concentrations of risk associated with derivative financial instruments.

The Company employs a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices 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. Capital Power's VaR for positions expected to settle in 2025, at December 31, 2024, 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. 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.

Notes to the consolidated financial statements

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

34. Risk management, continued:

Market risk, continued

Commodity price risk, continued

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.

These limitations and the nature of VaR measurements mean that 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. As VaR is not a perfect predictor of risk, the Company undertakes back testing and periodically calibrates the VaR calculations to a 99% confidence level.

The estimation of VaR considers positions from all wholly-owned subsidiaries and subsidiaries in which the Company has a controlling interest and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has approved the methodology for the ongoing determination of commodity risk limits, under their commodity risk management policy. The Executive Team has access to daily risk reports which provide key measures in relation to applicable limits and quarterly risk reports are reviewed by Capital Power's Audit Committee. The portfolios are stress tested regularly to observe the effects of plausible scenarios considering historical price movements and certain hypothetical extreme events. At December 31, 2024, the VaR of the Company's commodity trading and assets portfolios for 2025 as a result of unfavourable market price changes is $38 million based on a 99% confidence level and a holding period of 10 days.

Foreign exchange risk

The Company is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments, and monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign operations. The Company's operations expose it to foreign exchange risk arising from transactions denominated in foreign currencies. The Company's foreign exchange risk arises primarily with respect to the U.S. dollar but it is potentially exposed to changes in other currencies if and when it transacts in other currencies. The risk is that the functional currency value of cash flows will vary as a result of the movements in exchange rates.

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.

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. The largest exposure the Company had to foreign exchange movements in 2024 was related to the acquisitions of New Harquahala 1 Generating Company and CXA La Paloma and capital costs associated with Halkirk 2 Wind and the BESS projects for York and Goreway. The Company has entered into cash flow hedges, which have settled and will settle during 2024 and 2025 respectively, to mitigate the foreign exchange exposure on those transactions. At December 31, 2024, the Company held foreign exchange derivatives as disclosed in note 16.

At December 31, 2024, 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 $12 million (2023 – decreased or increased by $23 million) and would have decreased or increased other comprehensive income by $1 million (2023 – $1 million). This sensitivity analysis excludes translation risk associated with the translation of subsidiaries that have a different functional currency to the functional currency of the Company 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 the foreign exchange cash flow hedges.

Notes to the consolidated financial statements

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

34. Risk management, continued:

Market risk, continued

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate current and non-current loans and borrowings. The Company is exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments. The Company uses floating rate funding for current borrowings and other liquidity requirements. At December 31, 2024, the proportion of fixed rate loans and borrowings was approximately 94% of total loans and borrowings outstanding (2023 – 87%). The Company uses derivative instruments to manage interest rate risk. At December 31, 2024, the Company held interest rate derivatives as disclosed in note 16 which effectively fixed the Company's interest rate spread and increased the proportion of fixed rate loans and borrowings to 100% (2023 – 94%) at December 31, 2024.

Assuming that the amount and mix of fixed and floating rate loans and borrowings and net loans and borrowings remains unchanged from that held at December 31, 2024, a 100 basis point decrease or increase to interest rates would increase or decrease full year net income attributable to common shareholders by nil (2023 – $2 million) and would have no direct impact on other comprehensive income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company. The Company's counterparty credit risk management policy is established by the Executive Team and approved by the Board of Directors. The associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout 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 and concentrations are subsequently monitored and are regularly reported to management on an ongoing basis. Counterparty creditworthiness also continues to be evaluated on an ongoing basis after transactions have been initiated.

Credit risk is managed and mitigated through a number of risk mitigation practices such as securing parent company guarantees to enhance counterparty credit quality, negotiating and obtaining security (such as cash deposits, letters of credit or property) to offset potential losses, and margining to limit credit risk where applicable.

Maximum credit risk exposure

The Company's maximum credit exposure was represented by the following financial assets:

At December 31		2024		2023
Cash and cash equivalents (note 13)	$	**865**	$	1,423
Trade and other receivables (note 14)[2]		**604**		747
Derivative financial instruments assets (note 16)[2]		**656**		352
Finance lease receivable (note 17)		**13**		25
Government grants receivable (note 18)		**380**		269
	$	**2,518**	$	2,816

[2] 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 $859 million (2023 – $551 million) for wholesale counterparties and $401 million (2023 – $548 million) for generation and other counterparties at December 31, 2024.

The Company is not permitted to sell or re-pledge collateral in the absence of default of the collateral providers. At December 31, 2024, the Company also held other forms of credit enhancement in the forms of letters of credit of $168 million (2023 – $44 million) and parental guarantees of $3,693 million (2023 – $3,463 million) related to the financial assets noted above. At December 31, 2024 and 2023, the Company also held parental 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.

Notes to the consolidated financial statements

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

34. Risk management, continued:

Credit risk, continued

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 power purchase arrangements, 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.

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 and reviewing each investment vehicle to ensure the underlying credit risk is known.

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. Consequently, the Company's financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements. 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 also has credit exposures to large suppliers of electricity and natural gas.

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 including, when appropriate, taking appropriate security from the supplier.

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

34. Risk management, continued:

Credit risk, continued

Trade and other receivables, financial derivative instruments and allowance for doubtful accounts, continued

The aging of trade and other receivables at December 31, 2024 was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current[3]	$ 601	$ 2	$ 599
Outstanding 31–90 days	4	–	4
Outstanding greater than 90 days	1	–	1
	$ 606	$ 2	$ 604

[3] Current amounts represent trade and other receivables outstanding zero to 30 days. Amounts outstanding more than 30 days are considered past due.

At December 31, 2024, the Company held $5 million (2023 – $13 million) in customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers. At December 31, 2024, the Company recorded an allowance of $2 million (2023 – $2 million) for expected credit losses 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 centrally by the 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 addressed 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 CPLP subsidiary. The Company also ladders its debt maturities to avoid large repayments in a single year.

The Company's recent financings (see note 25) and renewable asset sell-down (see note 4) have reduced liquidity risk. Additionally, the Company also continues to have available committed credit facilities to draw upon as described below.

At December 31, 2024, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $1,836 million (2023 – $1,587 million), of which $1,000 million is committed to 2029 (2023 – $734 million committed to 2028).

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, 2024, 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.

Notes to the consolidated financial statements

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

34. Risk management, continued:

Liquidity risk, continued

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, 2024:

		Due between					
	Due within 1 year	1 and 2 years	2 and 3 years	3 and 4 years	4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Loans and borrowings[4] (note 25)	$ 84	$ 640	$ 495	$ 445	$ 266	$ 2,836	$ 4,766
Interest payments on loans and borrowings	257	242	209	191	162	510	1,571
Trade and other payables[5] (note 23)	681	–	–	–	–	–	681
Lease liabilities (note 20)	27	16	15	15	15	185	273
Derivative financial liabilities (net of financial assets):							
Commodity and other derivatives	41	49	49	40	40	100	319
Total	$ 1,090	$ 947	$ 768	$ 691	$ 483	$ 3,631	$ 7,610

4 Repayments of loans and borrowings exclude fair value differentials of $9 million related to debt assumed on previous asset acquisitions and $237 million related to repayments of tax-equity financing through non-cash tax-equity attributes.

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

35. 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	2024	2023
Loans and borrowings (note 25)	$ 4,976	$ 4,716
Subscription receipts[1] (note 24)	–	399
Lease liabilities[2] (note 20)	151	147
Cash and cash equivalents (note 13)	(865)	(1,423)
Net debt	4,262	3,839
Share capital (note 29)	4,301	3,524
Deficit and other reserves	275	(334)
Non-controlling interests	(5)	(4)
Total equity	4,571	3,186
Total capital	$ 8,833	$ 7,025

1 The Company's obligation for converting subscription receipts to common shares of Capital Power that were converted upon the closing of the La Paloma acquisition (note 5) in February 2024.

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

Notes to the consolidated financial statements

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

35. Capital management, continued:

Capital Power has senior unsecured long-term debt ratings of BBB- (stable outlook) and BBB (low) assigned by Standard & Poor's (S&P) and DBRS Limited (DBRS), respectively. Capital Power has preferred share ratings of P-3 (High) and Pfd-3 (low) assigned by S&P and DBRS, respectively.

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 net tangible assets to consolidated net tangible 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 assigned a rating of less than BBB- from S&P and BBB (Low) from DBRS (in each case with a stable outlook), 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, 2024 and 2023, 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.

36. Interests in joint arrangements and associates:

Joint operations

The Company holds interests in the following joint operations at December 31, 2024:

	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 in which Capital Power holds a 40% interest with external parties holding 40% and 20% interests, respectively.
[2] Shepard is an 860 MW gas-fired generating facility in which Capital Power holds a 50% interest while the other 50% is held by an external party.
[3] Frederickson 1 is a 265 MW natural gas-fired combined-cycle generating facility in which Capital Power holds a 50.15% interest while 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, 2024:

	Place of business	% of ownership interest
York Energy Centre L.P. (York Energy)[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 is a 400 MW natural gas-fired power generating facility, located in Ontario, Canada, in which Capital Power holds a 50% interest while 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. Capital Power holds a 50% interest in MCV Partners LLC and the other 50% is held by an external party. MCV Partners LLC owns 100% of MCV Holding Company LLC which owns 100% of Midland Cogen.
[6] Harquahala is a 1,092 MW natural gas-fired combined cycle generation facility, located in Maricopa County, Arizona (note 5). Capital Power holds a 50% ownership interest in the facility, with the other 50% owned by BlackRock. Capital Power operates, maintains, and manages the facility for an annual management fee.
[7] Quality Wind Limited Partnership (Quality Wind) is a 142 MW wind generation facility, located in British Columbia and PDN Limited Partnership (PDN Wind) is a 105 MW wind generation facility, located in Ontario. As of December 20, 2024, Capital Power holds 51% interests in these facilities while the other 49% interests are held by Axium (note 4). Practically, Capital Power will manage and operate the wind facilities pursuant to Asset Management Agreements with Quality Wind and PDN Wind. However, based on the terms of the partnership agreements, Capital Power jointly controls Quality Wind and PDN Wind with Axium.

Notes to the consolidated financial statements

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

36. 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 Partners LLC		Harquahala	PDN Wind	Quality Wind	Total	Total
Statements of Financial Position	**2024**	2023	**2024**	2023	**2024**	**2024**	**2024**	**2024**	2023
Cash and cash equivalents	**$ 41**	$ 10	**$ 86**	$ 74	**$ 24**	**$ 4**	**$ –**	**$ 155**	$ 84
Other current assets	**8**	18	**91**	73	**28**	**4**	**12**	**143**	91
Non-current assets	**217**	212	**1,123**	1,082	**1,002**	**137**	**226**	**2,705**	1,294
Other financial current liabilities	**–**	(14)	**(104)**	(98)	**(9)**	**(1)**	**–**	**(114)**	(112)
Trade and other payables	**(7)**	(3)	**(48)**	(39)	**(21)**	**(2)**	**(5)**	**(83)**	(42)
Financial non-current liabilities	**(312)**	(154)	**(424)**	(480)	**(435)**	**(6)**	**–**	**(1,177)**	(634)
Other non-current liabilities	**(2)**	(2)	**(4)**	(4)	**(25)**	**(5)**	**(9)**	**(45)**	(6)
Net assets	**$ (55)**	$ 67	**$ 720**	$ 608	**$ 564**	**$ 131**	**$ 224**	**$ 1,584**	$ 675

	York Energy		MCV Partners LLC		Harquahala	PDN Wind	Quality Wind	Total	Total
Statements of Income and Comprehensive Income	**2024**	2023	**2024**	2023	**2024**	**2024**	**2024**	**2024**	2023
Revenues	**$ 73**	$ 63	**$ 624**	$ 641	**$ 181**	**$ –**	**$ –**	**$ 878**	$ 704
Energy purchases and fuel	**(11)**	(9)	**(301)**	(315)	**(1)**	**–**	**–**	**(313)**	(324)
Other raw materials and operating charges	**(5)**	(5)	**(35)**	(30)	**(39)**	**–**	**–**	**(79)**	(35)
Staff costs and employee benefits expense	**–**	–	**(15)**	(18)	**–**	**–**	**–**	**(15)**	(18)
Other administrative expense	**(4)**	(3)	**(43)**	(30)	**(25)**	**–**	**–**	**(72)**	(33)
Depreciation and amortization	**(7)**	(7)	**(100)**	(96)	**(46)**	**–**	**–**	**(153)**	(103)
Gains (losses) on disposals and other transactions	**1**	–	**–**	–	**–**	**–**	**–**	**1**	–
Finance expense	**(14)**	(6)	**(29)**	(34)	**(30)**	**–**	**–**	**(73)**	(40)
Net income	**33**	33	**101**	118	**40**	**–**	**–**	**174**	151
Other comprehensive income that will not be reclassified to net income	**–**	–	**(2)**	–	**–**	**–**	**–**	**(2)**	–
Other comprehensive (loss) income that are or may be reclassified to net income	**–**	–	**(1)**	(9)	**6**	**–**	**–**	**5**	(9)
Net income and comprehensive income	**$ 33**	$ 33	**$ 98**	$ 109	**$ 46**	**$ –**	**$ –**	**$ 177**	$ 142

Notes to the consolidated financial statements

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

36. 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 Partners LLC		Harquahala	PDN Wind	Quality Wind	Total	Total
	2024	2023	**2024**	2023	**2024**	**2024**	**2024**	**2024**	2023
At January 1	**$ 129**	$ 126	**$ 296**	$ 281	**$ –**	**$ –**	**$ –**	**$ 425**	$ 407
Acquisition (note 5)	**–**	–	**–**	–	**316**	**149**	**190**	**655**	–
Proportionate share of net income	**16**	16	**51**	59	**20**	**–**	**–**	**87**	75
Distributions received – operating	**(76)**	(3)	**(20)**	(33)	**(24)**	**–**	**–**	**(120)**	(36)
Other Comprehensive Income (loss)	**–**	–	**3**	(4)	**3**	**–**	**–**	**6**	(4)
Amortization of the Company's fair value of net assets acquired	**(11)**	(10)	**–**	–	**–**	**–**	**–**	**(11)**	(10)
Foreign exchange gain (loss)	**–**	–	**28**	(7)	**22**	**–**	**–**	**50**	(7)
At December 31	**$ 58**	$ 129	**$ 358**	$ 296	**$ 337**	**$ 149**	**$ 190**	**$ 1,092**	$ 425

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 Partners LLC	Harquahala	PDN Wind	Quality Wind	Total
Within one year	**$ 16**	**$ 50**	**$ 22**	**$ 5**	**$ 5**	**$ 98**
Between one and five years	**16**	**78**	**96**	**21**	**22**	**233**
After five years	**21**	**13**	**196**	**22**	**17**	**269**
	$ 53	**$ 141**	**$ 314**	**$ 48**	**$ 44**	**$ 600**

Associate

At December 31, 2024, the Company's equity-investment in its associate C2CNT is $4 million (US$3 million) (2023 – $30 million (US$23 million)). An impairment of $27 million (US$20 million) was recorded in 2024 on the equity-investment (note 9). No income or operating cash flow has been earned in the year.

Notes to the consolidated financial statements

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

37. Commitments and contingencies:

(a) The Company is committed to the following growth projects at December 31, 2024:

Projects	Contracted Capacity	Expected capital cost (post commercial operation date)	Completion date	Location
Completed Growth Projects:				
Repowering of Genesee 1 and 2	512 MW	$63 – $163	Achieved commercial operations Q4 2024	Alberta

Projects	Contracted Capacity	Expected capital cost	Expected completion date[1]	Location
Growth Projects:				
Maple Leaf Solar[1]	73 MWac	$219	Q1 2027	North Carolina
Ontario growth projects[2]	276 MW	$600	2025 – 2026	Ontario
Halkirk 2 Wind[3]	126 MW	$311	Q2 2025	Alberta
Bear Branch Solar[4]	35 MW	$103	Second half of 2026	North Carolina
Hornet Solar[4]	73 MW	$187	Second half of 2026	North Carolina
Commercial Initiatives:				
Goreway and York Energy Upgrades[5]	78 MW	$86	2025	Ontario

[1] On June 29, 2023, the Company announced it executed a 25-year, fixed price renewable power purchase agreement (PPA) for 100% of the output from its Maple Leaf Solar project (Maple Leaf or the Project) with Duke Energy Progress (DEP). Maple Leaf is a 73 MWac (92 MWdc) solar development project in Selma, North Carolina. The construction of the Project is planned to begin in 2025 at a total cost of approximately $219 million (US$165 million) with an expected commercial operations date in the first quarter of 2027, pending completion of the Duke interconnection upgrades.

[2] On June 29, 2023, the Company announced that it has:

- Executed two long-term contracts for the East Windsor Expansion (81 MW summer and 100 MW winter contracted capacities) and the York BESS project as part of the IESO's Expedited Long-Term request for proposals process. The York BESS is expected to begin commercial operations in 2025 and the East Windsor Expansion has been updated to begin commercial operations in 2026 due to delays in permitting processes. Capital Power holds a 100% interest in the York Energy BESS project.
- Been selected as a successful proponent for the Goreway BESS project as part of Category 2 of the Ontario IESO's Expedited Long-Term request for proposals. The contract was subsequently executed in July 2023 and the project is expected to enter service in 2025.

[3] On July 19, 2024, the Company signed a three-year partnership and equity option agreement with the Louis Bull Tribe, Ermineskin Cree Nation, Montana First Nation and Samson Cree Nation of Maskwacis located in Alberta. Following the three-year agreement, the Company is offering the four First Nations an opportunity to acquire a combined total of 25% of Halkirk 2 Wind. As part of the Company's commitment to reconciliation, the agreement provides an equitable profit-sharing model that supports a pathway to future, long-term equity ownership in the project that can support these nations with sustainable income throughout the lifetime of its operations.

[4] In June 2024, the Company successfully executed 25-year power purchase agreements with Duke Energy Carolinas for the Hornet Solar and Bear Branch Solar projects located in North Carolina totalling 107.5 MW. Hornet Solar began construction in August 2024 and Bear Branch is expected to commence construction in the first half of 2025. Targeted commercial operations for both projects is expected in the second half of 2026.

[5] On April 25, 2023, Capital Power and the Ontario Independent Electric System Operator (IESO) executed a 6-year contract extension for Goreway associated with its successful efficiency upgrade bid of approximately 40 megawatts (MW) in IESO's competitive capacity procurement process. The upgrade will increase Goreway's current combined contracted capacity from 840 MW to 880 MW. The IESO contract extension applies to the new combined contracted capacity of 880 MW and extends the current Clean Energy Supply Contract from 2029 to 2035. The upgrade is expected to be completed in 2025. Goreway is a natural gas-fired combined cycle facility located in Brampton, Ontario.

On June 29, 2023, the Company announced that it executed a 3-year contract extension for York Energy for approximately 38 MW that will increase York Energy's contracted capacity from 393 MW to 431 MW. The contract extension applies to the new contracted capacity of 431 MW (date of the upgrades expected in 2025) and extends the current contract from 2032 to 2035. Expected capital cost represents Capital Power's 50% ownership interest in the York Energy joint venture.

(b) 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[6]	Operating and maintenance contracts	Environmental credits[7]
Within one year	$ 286	$ 103	$ 189
Between one and five years	721	313	430
After five years	219	507	20
	$ 1,226	$ 923	$ 639

[6] Based on gross settlement amounts.

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

Notes to the consolidated financial statements

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

37. Commitments and contingencies, continued:

(c) 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, 2024. The Company believes the various agreements governing the termination and transfer of the Sundance C PPA and related transmission agreements with the AESO had the effect of transferring all past liabilities for the Sundance C PPA to the Balancing Pool. Capital Power has therefore filed a statement of claim at the Alberta Court of Queen's Bench on January 11, 2021 against the Balancing Pool, the Province of Alberta and the AESO in which it is seeking, among other relief, recovery from the Balancing Pool and the Province of Alberta of all amounts Capital Power was compelled to pay to the AESO on account of the LLR adjustment invoices relating to the Sundance C PPA as well as interest and legal costs, including the portion invoiced to the Balancing Pool but not received by the Company pertaining to all tranches of invoices. This process remains ongoing. Capital Power expects to ultimately realize the full amount of the gross receivables related to the line losses upon resolution of the dispute before the Court.

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

A dispute has arisen between the Company and the contractor regarding construction work on the Genesee Repowering Project. The parties are actively participating in an agreed-upon mediation process to resolve the claims by both parties. The Company has withheld payments pending the resolution of the dispute which is at a preliminary stage. The Company is still reviewing the claims and at this time the outcome of the mediation process is uncertain.

38. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $608 million (2023 – $559 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

39. Segment information:

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

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

	Year ended December 31, 2024				Year ended December 31, 2023			
	Canada	**U.S.**	**Inter–area eliminations**	**Total**	Canada	U.S.	Inter–area eliminations	Total
Revenues – external[1]	**$ 2,694**	**$ 983**	**$ –**	**$ 3,677**	$ 3,590	$ 478	$ –	$ 4,068
Revenues – inter-area	**51**	**–**	**(51)**	**–**	31	–	(31)	–
Other income	**23**	**76**	**–**	**99**	143	71	–	214
Total revenues and other income	**$ 2,768**	**$ 1,059**	**$ (51)**	**$ 3,776**	$ 3,764	$ 549	$ (31)	$ 4,282

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

Notes to the consolidated financial statements

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

39. Segment information, continued:

	At December 31, 2024			At December 31, 2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Property, plant and equipment	**$ 5,457**	**$ 2,604**	**$ 8,061**	$ 4,898	$ 1,659	$ 6,557
Right-of-use assets	**54**	**64**	**118**	59	59	118
Intangible assets and goodwill	**519**	**225**	**744**	631	144	775
Equity-accounted investments (note 36)	**397**	**699**	**1,096**	129	326	455
Finance lease receivable[2] (note 17)	**25**	**–**	**25**	34	–	34
Other assets	**48**	**84**	**132**	47	63	110
	$ 6,500	**$ 3,676**	**$ 10,176**	$ 5,798	$ 2,251	$ 8,049

[2] Includes current portion.

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

	Year ended December 31, 2024						
	Alberta Commercial facilities	**Western Canada facilities**	**Ontario facilities**	**U.S. facilities**	**Total from contracts with customers**	**Other sources**	**Total**
Energy revenues	**$ 1,545**	**$ 97**	**$ 360**	**$ 489**	**$ 2,491**	**$ 1,044**	**$ 3,535**
Emission credit revenues	**22**	**22**	**–**	**3**	**47**	**95**	**142**
Total revenues[3]	**$ 1,567**	**$ 119**	**$ 360**	**$ 492**	**$ 2,538**	**$ 1,139**	**$ 3,677**

	Year ended December 31, 2023						
	Alberta Commercial facilities	Western Canada facilities	Ontario facilities	U.S. facilities	Total from contracts with customers	Other sources	Total
Energy revenues	$ 2,620	$ 147	$ 358	$ 224	$ 3,349	$ 632	$ 3,981
Emission credit revenues	23	12	–	4	39	48	87
Total revenues[3]	$ 2,643	$ 159	$ 358	$ 228	$ 3,388	$ 680	$ 4,068

[3] Included within trade and other receivables, at December 31, 2024, were amounts related to contracts with customers of $255 million (2023 – $442 million).

Appendix

TCFD alignment table

Task Force on Climate-Related Financial Disclosures (TCFD)

This section reviews our strategy and its resiliency in relation to climate change scenarios 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	▸ 2024 Integrated Annual Report, Corporate governance ▸ 2025 Management Proxy Circular, Sustainability and climate oversight ▸ Who we are > Corporate governance (www.capitalpower.com)
	Describe management roles in assessing and managing climate-related opportunities and risk	▸ 2024 Corporate governance ▸ 2025 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 ▸ 2024 Integrated Annual Report, Executing our strategic focus
	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	▸ 2024 Integrated Annual Report, Our approach to risk management ▸ 2024 Integrated Annual Report, Risks and impacts, Climate change, Business report ▸ TCFD Risks and opportunities tables
	Describe processes for managing climate-related risks	▸ 2024 Integrated Annual Report, Our approach to risk management ▸ 2024 Integrated Annual Report, Risks and impacts, 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	▸ 2024 Integrated Annual Report, Our approach to risk management ▸ 2024 Integrated Annual Report, Risks and impacts, 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	▸ 2024 Integrated Annual Report, 2025 performance targets ▸ 2024 Integrated Annual Report, Emissions management
	Disclose Scope 1, 2, and 3 GHG emissions and related risks	▸ 2024 Integrated Annual Report, Emissions management
	Describe targets used by the Company to manage climate-related opportunities and risks, and performance against targets	▸ 2024 Integrated Annual Report, 2025 performance targets ▸ 2024 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 evaluates opportunities and risks under varying climate change conditions to understand the resiliency of our strategy. The International Energy Agency (IEA) scenarios and underlying assumptions are considered in Capital Power's analysis. The scenarios provide a high-level starting point for the assessment of climate change impacts and allow us to model scenarios in specific jurisdictions that result in equivalent outcomes. As we evaluate the risks and opportunities that may arise in these scenarios, our analysis focuses on the material risks that are relevant to our business.

TCFD alignment table

IEA scenarios

The IEA scenarios make assumptions about technology advancement, policy, CO_2 prices, fuel prices, and socio-economic drivers, including population and GDP, and considers global trends towards increasing net zero commitments by governments and corporations. The IEA scenarios simulate the interactions among supply and demand fundamentals and model the resulting energy flows, CO_2 emissions and investments to 2050.

The IEA's 2024 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 2024 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.
- **Announced Pledges Scenario** (APS) assumes that climate-related commitments made by governments and implemented through Nationally Determined Contributions (NDCs) will be met in full and on time.
- **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 2024 IEA scenarios and the resiliency of our strategy

The 2024 IEA scenarios explore how the energy system might evolve over time and take into account the critical steps required to limit the effects of climate change and achieve net zero emissions by 2050. The IEA scenarios are used to shape the assumptions in our own scenarios including factors like supply adequacy, thermal limits on power plants, and long-term demand influenced by varying climate extremes. These factors impact our perspective on technology costs and deployment. We model different scenarios with various technology mixes and monitor emission-reduction technologies as they become economically viable.

Electricity security continues to be of global concern with increasing demand highlighting the importance of secure, resilient and flexible power systems. Thermal power, along with batteries and hydropower, are anticipated to be the main sources of seasonal and short-term flexibility today and remain through to 2050. Our corporate strategy prioritizes the need for flexible and diverse sources of supply to retain reliability and we believe that natural gas will continue to play an integral role in meeting the need for reliable and affordable power while enabling the transition to a lower-carbon economy.

We have reassessed our 2030 interim and 2045 net zero targets considering our scenarios, as well as our corporate strategy, to meet the immediate needs of the energy expansion while simultaneously addressing long-term sustainability objectives. Based on this assessment, we will not meet these targets while also providing reliable and affordable energy to our customers and have made the decision to retire both our interim 2030 and 2045 net zero targets. Capital Power has refreshed its roadmap towards a lower-carbon future to support the immediate demand for reliable and affordable power, as well as long-term sustainability outcomes. Lower-carbon solutions are essential to Capital Power's long-term strategy resiliency, and we continue to explore and develop expertise with lower-carbon solutions, including CCS and SMR, to strengthen our strategic resiliency.

As global electricity demand grows, a mix of lower-carbon energy sources will be needed to power the global economy. Capital Power's renewable energy development will be resilient in all future scenarios and a transition in thermal generation from unabated generation towards combustion of lower-carbon fuels and operations paired with decarbonization technologies will be essential to long-term resiliency. The pace at which this transition occurs will vary by scenario.

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 U.S. ▸ Stimulus spending by governments is increasingly focused on energy and lower-carbon infrastructure. ▸ Demand growth accelerates globally due to electrification. ▸ 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	▸ Accelerated decarbonization of the power sector in Canada and the U.S. ▸ 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 lower-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 is pursued 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.
	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 part of the supply mix long-term. ▸ 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 lower-emission sources of electricity may reduce market share for natural gas generation. ▸ Policy that limits the use of natural gas as a fuel source for electricity generation poses a risk to long-term viability of new and existing thermal assets. 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 lower-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 colocation.
	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. ▸ Deployment of technologies that support decarbonization such as SMR and post-combustion CCS technologies, where commercially viable. ▸ In jurisdictions where competitiveness of natural gas is significantly reduced, shift capital allocation to alternative assets including renewables. Capital Power's capital 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 lower-carbon power will drive innovation and transformation of the power sector. ▸ Awareness and concern among end-use consumers of their contribution to climate change will drive behavioral 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	▸ 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. ▸ Changes to wind regimes and solar resources may reduce the revenues and competitiveness of existing resources.
	Mitigation	▸ Actively monitor policy and market fundamentals that may drive investment in disruptive technologies that could affect asset competitiveness and financials. ▸ Conduct due diligence assessments to 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 emissions 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 Renewal 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 emissions abatement technology encourages the pursuit of new innovations. This could include the acquisition of new assets or companies with innovative technology. ▸ 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	▸ Technological advancement and digitalization allow greater control of energy generation and consumption by demand-side market participants. ▸ Emissions 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 natural gas generation, including CCS, hydrogen and direct air capture applications. ▸ Seek funding for projects to assess promising emerging technologies that can reduce emissions in line with the Company's strategy. ▸ Pursue contracting opportunities with corporate off-takers to secure the output of new and existing assets. ▸ Establish partnerships to advance innovations and early-stage emissions abatement technologies. ▸ Consider 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-related impacts have the potential to create material reputational risks.	
Risks	**Short-Term**	▸ Investors are increasingly averse to investments that exhibit higher risks 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-intensive 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. ▸ Counter parties and off-takers favour generators with lower exposure to climate change.
	Long-Term	▸ Increasing frequency and severity of climate-related events may affect company assets and create reputational and investor risk. ▸ Cost of capital could increase due to changing investor sentiment in relation to climate-related financing.
	Mitigation	▸ Future consideration of opportunities to tie our environmental performance to our financing activities to demonstrate our commitment and leadership in achieving our corporate objectives. ▸ Coal-fired generation is phased out, with our investment in repowering at the Genesee facility. ▸ ESG criteria is integrated into our investment decisions to ensure appropriate consideration of climate-related risks. ▸ Commitment to actively manage our exposure and 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-related events on physical assets, financial position and reputation. ▸ Adjust 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-related impacts that affect operations may also affect Capital Power's reputation as a reliable power generator in the communities where we operate. ▸ The pursuit of credible decarbonization strategies demonstrates leadership that builds trust with investors and stakeholders.
	Long-Term	▸ Companies that actively manage their exposure to climate-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-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 disrupt regular operations or 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-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-related events.

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, limiting the availability of water usage to Capital Power or increasing operating costs to acquire the resource. ▸ Costs associated with increasing water management requirements may affect supply fundamentals.
	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. ▸ Monitors water use and implements 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.
	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-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 invests 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 lower-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-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-related impacts, such as extreme weather events, 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.
	Mitigation	▸ Monitors regulatory developments relating to fugitive methane emissions to assess risks to fuel supply and costs. ▸ Approves and implements 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	▸ Lower-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 intelligence 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 lower-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 lower-emitting, reliable, and affordable 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-related events may cause disruptions to operations, or supply chain disruptions, 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 interest by customers to secure contracted sources of reliable and affordable power as more frequent extreme weather events may impact grid stability and create power price volatility.
	Long-Term	▸ Decarbonization through increased electrification will support long-term emissions reduction objectives, including net zero commitments.
	Response	▸ 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	2024 response
Gross global Scope 1 emissions	Quantitative	Metric tonnes (t) CO_2e	IF-EU-110a.1	17,431,328 See the 2024 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	69%
Percentage of gross global Scope 1 emissions covered emissions-reporting regulations	Quantitative	Percentage (%)	IF-EU-110a.1	99% Approximately 1% of our gross global Scope 1 emissions are from auxiliary gas combustion at U.S. facilities. These emissions are not covered by emissions reporting-regulations.
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 Management Proxy Circular and HSSE Policy. See the 2024 Integrated Annual Report, Executing our strategic focus section and Emissions management section.

Air quality

SASB disclosure	Category	Unit of measure	SASB disclosure reference	2024 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	Air emissions and the percentage of each in or near areas of dense populations

	NO_x (tonnes/yr)	SO_2 (tonnes/yr)	Total PM (tonnes/yr)	Hg (kg/yr)
Air emissions	10,369	2,719	864	0.0063481
% near areas of dense population	42%	2%	73%	0%

SASB Index

SASB disclosure	Category	Unit of measure	SASB disclosure reference	2024 response
Water management				
Total water withdrawn	Quantitative	Thousand cubic metres (m³)	IF-EU-140a.1	60,072 ML 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 (m³)	IF-EU-140a.1	24,752 ML 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 World Wildlife Fund (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 16,769 ML (18% of total water withdrawals) and consumed 10,439 (42% of total water consumption) of water in 2024.
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 2024.
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 water consultations as needed.
Coal ash management				
(1) Amount of coal combustion products (CCPs) generated, (2) percentage recycled	Quantitative	Metric tonnes (t), percentage (%)	IF-EU-150a.1	Coal Ash Management tonnes / % Ash Disposed: 90,300 / 67% Ash Recycled: 44,971 / 33%
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	We prioritize safely delivering reliable and affordable power. For more information about our strategy, see the 2024 Integrated Annual Report, Executing our strategic focus section.

SASB Index

SASB disclosure	Category	Unit of measure	SASB disclosure reference	2024 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: 0.53 Fatality rate: 0 NMFR: 4.34 Note: All rates include all contractors in operations and Capital Power employees. They do not include construction projects. See the 2024 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	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.
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 track customer electricity savings from efficiency measures.
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 2024 was 92%.

SASB Index

Table 2. Activity Metrics

Activity metrics	Category	Unit of measure	SASB disclosure reference	2024 response
Number of: (1) residential, (2) commercial, and (3) industrial customers served	Quantitative	Number	IF-EU-000.A	Capital Power had approximately 182 commerical and industrial customers in 2024.
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 2024 Integrated Annual Report, Business 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	Megawatt hours (MWh), percentage (%)	IF-EU-000.D	See 2024 Integrated Annual Report, Business 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.

For the Genesee Mine, we have previously reported Scope 1 emissions as we hold the environmental operating approval for the facility. However, we have not reported any other sustainability information for this facility because it is independently operated by a separate entity, which Capital Power has no authority over. As of the end of 2023, Genesee Mine ceased mining operations and is conducting reclamation activities. As such, Genesee Mine emissions are no longer included in our reporting.

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. Information that was not available for December due to timing of the report was estimated.

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 2024, biomass emissions for 2024 were 1,492 tCO_2e.

TRIF

Total Recordable Incident Frequency (TRIF) reflects recordable occupational injuries of employees and contractors that occurred in areas where Capital Power had full care, custody, and control of the work area, the work and the workers. Our Harquahala and La Paloma facilities, although within Capital Power's operational control for the purpose of accounting for emissions and emissions intensity data because we hold the environmental operating approvals for these facilities, are contractually under the care, custody and control of a third-party operator for the purpose of health and safety (H&S) management. As such, recordable incidents and exposure hours at these facilities were not reflected in Capital Power's TRIF.

In 2024, we refined our TRIF calculation to exclude incidents and exposure hours that occurred in work areas within our operated sites that fall under the health and safety management systems of partners or third-party vendors (i.e. where Capital Power's H&S Management System is not in force). This relates specifically to incidents and exposure hours in areas of our wind facilities that are under the care, custody and control of a third-party. This includes work done in wind turbines and their immediate vicinity, and within third-party managed support facilities. These exclusions led to an immaterial increase to the 2024 TRIF.

Consistent with years past, TRIF also does not included incidents from construction projects (employee or contractor). These activities can vary significantly from year to year and are distinct in nature from our core operations.

Gender diversity

Gender diversity data includes all permanent employees, temporary and temporary extended employees, casual employees and employees on maternity/parental leave as of December 31, 2024. Contractors, pensioners, Board members, students, and employees on long-term disability (LTD) as of December 31, 2024, are excluded. Data was collected for employees only, by gender as specified by employees themselves, as either woman or man at the time of employee onboarding.

La Paloma and Harquahala were operated by a third-party contractor in 2024. Since contractors are not included in our boundary for gender diversity, these individuals are not accounted for in reported data.

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 Frederickson 1, La Paloma, and Harquahala facilities which were acquired on December 28, 2023; February 9, 2024; and February 16, 2024, respectively.

Data for Frederickson 1 was limited at the time of prior year report development due to the proximity of the acquisition to December 31, 2023, and was therefore excluded from the 2023 IAR. Timing of the Frederickson revisions were dependent on gaining access to historical emissions data, and therefore emissions were not revised in 2023 annual reporting.

As per GHG Protocol guidance which allows for data to be reported in the following subsequent period if data is unavailable at time of reporting, past years' Frederickson 1 Scope 1 emissions and emissions intensity data is included in the revised data disclosed in this report.

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 13,742,607 to 15,627,451 tCO_2e
- 2022: Revision from 15,908,540 to 18,112,740 tCO_2e
- 2023: Revision from 16,234,470 to 18,751,151 tCO_2e

The revised emissions intensities disclosed in this report are as follows:

- 2021: Revision from 0.52 to 0.51 tCO_2e/MWh
- 2022: Revision from 0.51 to 0.50 tCO_2e/MWh
- 2023: Revision from 0.48 to 0.47 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.
- Total recordable incident frequency (TRIF): Total recordable injury frequency (work-related injury / 200,000 hours worked) within our TRIF reporting boundary.
- Women: Employees that self-identified as a woman at the time of employee onboarding within our gender reporting boundary.
- Employee: A worker hired directly by Capital Power at a specific pay rate defined through an agreement with our Company.
- Contractor: An individual who is hired for a specific business purpose at a set pay rate for specified period.
- Executive: Members of the Executive Team.
- Upper Management: Employees in non-executive management roles including Vice Presidents, Chief Officers, Heads of, Directors, Senior Leads, Senior Managers, Plant Managers, Senior Project Managers, Project Managers, Senior Advisors, Senior SMEs, OCE Specialists, and Senior Specialists.
- Support / Front Line: Employees in administration, operations and front line roles, excluding Executive, Upper Management, and Professional roles.
- Professional: All other employees not included in the Executive, Upper Management, and Support / Front Line Management categories. Professional includes non-management commodity trading roles.

10-Year Operational and Financial Highlights

(millions of dollars except per share and operational amounts) (unaudited)

	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015
OPERATIONAL										
Number of facilities at year-end[1]	**30**	30	29	26	28	26	25	24	18	18
Electricity generation (GWh)	**37,821**	32,487	28,573	22,811	23,806	24,527	20,229	17,194	15,328	14,567
Facility availability	**92%**	95%	93%	90%	95%	94%	95%	96%	94%	95%
Financial Position (at December 31)										
Total assets[7]	**$12,930**	$11,156	$10,133	$9,073	$8,911	$8,582	$7,569	$6,819	$6,062	$5,393
Loans and borrowings including current portion	**$4,976**	$4,716	$3,726	$3,360	$3,552	$3,413	$2,647	$2,146	$1,508	$1,615
Income and Cash Flow										
Revenues and other income[2,7]	**$3,776**	$4,282	$2,983	$1,990	$1,937	$1,963	$1,417	$1,168	$1,214	$1,241
Adjusted EBITDA[3,6,7,8]	**$1,333**	$1,455	$1,353	$1,124	$955	$1,029	$736	$614	$509	$483
Net income[7]	**$701**	$737	$168	$87	$130	$119	$258	$125	$102	$86
Net income attributable to shareholders[7]	**$699**	$744	$178	$98	$136	$125	$265	$135	$111	$90
Basic earnings per share[7]	**$5.16**	$6.07	$1.19	$0.39	$0.78	$0.73	$2.17	$0.98	$0.91	$0.70
Diluted earnings per share[4,7]	**$5.15**	$6.04	$1.19	$0.39	$0.77	$0.72	$2.16	$0.98	$0.91	$0.70
Net cash flows from operating activities	**$1,144**	$822	$935	$867	$611	$720	$450	$372	$375	$419
Adjusted funds from operations[3,5]	**$817**	$819	$848	$605	$522	$555	$397	$361	$291	$324
Adjusted funds from operations per share[3,5]	**$6.34**	$6.99	$7.28	$5.40	$4.96	$5.32	$3.85	$3.58	$3.02	3.36
DIVIDENDS										
Dividends declared per common share	**$2.53**	$2.39	$2.26	$2.12	$1.99	$1.86	$1.73	$1.62	$1.51	$1.41
Common Share Information (TSX:CPX)										
High	**$68.73**	$46.90	$51.90	$45.05	$38.88	$35.09	$29.79	$26.51	$24.49	$27.12
Low	**$33.90**	$35.11	$36.65	$33.31	$20.23	$26.22	$22.15	$23.15	$16.37	$15.41
Close	**$63.72**	$37.84	$46.33	$39.46	$34.98	$34.39	$26.59	$24.49	$23.23	$17.77
TSX volume (millions)	**125.8**	90.4	93.1	73.3	103.1	77.1	65.4	62.8	73.2	79.8

1 Commencing in 2024, the Company commenced referring to the Genesee Generating Station as a single facility in our portfolio (previously Genesee 1, 2 and 3, separately) as Genesee Repowering achieved commercial operations in the year.

2 Revenues for 2014 and 2015 have been restated to the 2016 basis of presentation.

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 Integrated Annual 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 Integrated Annual 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 2014 to 2018 have been restated to correspond to the 2019 basis of presentation.

7 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.

8 Commencing in 2023, the Company refined its adjusted EBITDA measure to better reflect the purpose of the measure and include in its adjustment to exclude other items affecting facility operations that are not reflective of the long-term performance of the Company's underlying business. Comparative adjusted EBITDA figures have not been restated to reflect the above refinements to the adjusted EBTIDA metric.

Investor information

Investor Relations

11th Floor 10423 101 Street NW
Edmonton, AB, Canada T5H 0E9
Phone: 1-866-896-4636 (toll-free)
investor@capitalpower.com
www.capitalpower.com

Registrar and Transfer Agent

Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, ON, Canada M5J 2Y1
Phone: 1-800-564-6253
(Toll-free in Canada and the U.S.)
514-982-7555 (international direct dial)

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, 2024)

Total outstanding shares: 138,979,428

Market capitalization: $8.86 billion

2025 Expected Common Share Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
Quarter 1	Mar 28	Mar 31	Apr 30
Quarter 2	Jun 27	Jun 30	Jul 31
Quarter 3	Sept 29	Sept 29	Oct 31
Quarter 4	Dec 30	Dec 31	Jan 30, 2026

2025 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

10-year Relative Price Performance for Common Shares (CPX)

Capital Power

Corporate Headquarters
1200 – 10423 101 St N.W.
Edmonton, AB T5H 0E9

info@capitalpower.com

www.capitalpower.com

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