BC Hydro and Power Authority

2025/26
Annual Service Plan Report

August 2026

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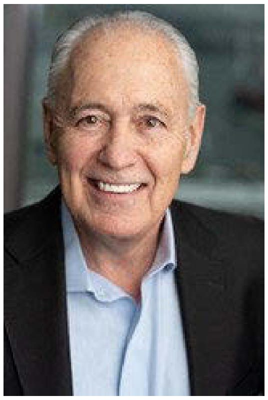
Board Chair's Accountability Statement



The BC Hydro and Power Authority 2025/26 Annual Service Plan Report compares the organization's actual results to the expected results identified in the 2025/26 – 2027/28 Service Plan published in 2025. The Board is accountable for those results as reported.

Signed on behalf of the Board by:

Glen Clark
Board Chair
July 31, 2026

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Letter from the Board Chair & CEO

On behalf of the Board of Directors and all BC Hydro employees, we are pleased to submit BC Hydro's Annual Service Plan Report for the fiscal year ending March 31, 2026.

British Columbia is entering a period of significant transformation for its electricity system. Global economic uncertainty, evolving trade relationships and a changing climate are reshaping how electricity infrastructure is planned, built and operated. At the same time, we are forecasting a significant and sustained increase in electricity demand, driven by continued population growth, widespread electrification of homes and transportation, and expanding economic activity, particularly in energy-intensive industrial sectors. In this evolving environment, we advanced important long-term initiatives to prepare for future electricity needs, investing to expand supply, modernize infrastructure, and strengthen system reliability. These efforts are focused on ensuring British Columbia's electricity system can support growing communities and economic development across the province, while continuing to deliver safe, reliable and affordable electricity for customers.

A key milestone this year was the submission of BC Hydro's 2025 Integrated Resource Plan (IRP) to the British Columbia Utilities Commission (BCUC) in October 2025. The IRP sets out how BC Hydro will meet customers' electricity needs over the next 20 years and beyond under a range of future demand scenarios. It provides a flexible, long-term roadmap to support economic growth and keep electricity affordable. The IRP confirms that electricity demand is rising faster than previously anticipated, with forecast electricity use in British Columbia increasing by approximately 20 per cent by 2030.

To respond to this growing demand, we took several significant steps to increase supply and capacity. In August 2025, the Site C hydroelectric project was completed and placed into full operation. With all six generating units now online, Site C is delivering more than 1,100 megawatts of electricity, and about 5,000 gigawatt hours of energy each year. This is enough clean electricity to power approximately 500,000 homes, increasing provincial supply by about eight per cent and strengthening long-term energy security for British Columbians. Building on this momentum, BC Hydro launched the 2025 Call for Power, targeting up to 5,000 gigawatt hours of new clean electricity. This followed the successful 2024 Call for Power, which will see 10 new clean and renewable energy projects built, delivering enough electricity to power approximately 500,000 homes.

Energy efficiency continued to play a critical role in meeting demand and managing system costs. This year, BC Hydro advanced our Power Smart programs and launched a Request for Expressions of Interest for market-ready technologies that help households and businesses save energy, lower electricity bills and reduce pressure on the electricity system. In May 2025, we also issued a Request for Expressions of Interest to explore new firm and baseload capacity. The strong response, with 106 submissions, demonstrated significant market readiness to deliver new clean electricity resources.

We also continued advancing our $36 billion 10-Year Capital Plan, investing in critical generation, transmission and distribution infrastructure to meet growing demand and improve reliability. At the same time, we took significant action to make electrical connections faster, simpler and more cost-effective for customers. This included updates to our Distribution Extension Policy to better support housing development and community growth while maintaining fairness and affordability for all customers.

Electricity demand is rising globally as emerging high-load industries, including artificial intelligence and data centres, expand rapidly. During 2025/26, BC Hydro worked closely with the Province to introduce a clear and transparent process to manage the strategic growth of these sectors in British Columbia. This approach ensures electricity is directed to projects that deliver the greatest benefits for British Columbians, support long-term economic value, and protect affordability and reliability for all customers.

Affordability and customer support remained central priorities throughout the year. BC Hydro introduced an optional residential flat rate, providing customers with greater flexibility and opportunities to save as they electrify their homes and transportation. Investments in energy efficiency continued to deliver strong results, with record participation in the Team Power Smart program, helping customers lower their bills while reducing pressure on the electricity system.

We are proud of what we achieved this year. Looking ahead, we will continue working closely with the Province, First Nations, communities and customers to deliver for British Columbians by expanding clean electricity supply, supporting economic growth, keeping rates affordable and building the infrastructure needed to power our province’s future. Above all, we remain committed to ensuring our workforce, and everyone who interacts with our system, goes home safely every day.

Glen Clark
Board Chair, BC Hydro
July 31, 2026

Charlotte Mitha
President and CEO, BC Hydro
July 31, 2026

Purpose of the Annual Service Plan Report

This annual service plan report has been developed to meet the requirements of the Budget Transparency and Accountability Act (BTAA), which sets out the legislative framework for planning, reporting and accountability for Government organizations. Under the BTAA, a Minister Responsible for a government organization is required to make public a report on the actual results of that organization's performance related to the forecasted targets stated in the service plan for the reported year.

Strategic Direction

The strategic direction set by Government in 2024 and the Board Chair's Mandate Letter from the Minister Responsible shaped the goals, objectives, performance measures and financial plan outlined in the BC Hydro 2025/26 – 2027/28 Service Plan and the actual results reported on in this annual report.

Purpose of the Organization

BC Hydro is one of the largest electric utilities in Canada and is publicly owned by the people of British Columbia. We generate and provide electricity to 95 per cent of B.C.'s population and serve approximately five million people. The electricity we generate and deliver to customers throughout the province powers our economy, our homes and our quality of life. Our mission is to safely provide our customers with reliable, affordable, and renewable electricity. As a provincial Crown Corporation, BC Hydro reports to the Provincial Government through the Minister of Energy and Climate Solutions. Government's expectations are expressed through the following legislation and policies:

- The Hydro and Power Authority Act
- The Utilities Commission Act
- The BC Hydro Public Power Legacy and Heritage Contract Act
- The Clean Energy Act

The Hydro and Power Authority Act gives BC Hydro its mandate to generate, manufacture, conserve, supply, acquire, and dispose of power and related products.

Powerex Corp. (Powerex) and Powertech Labs Inc. (Powertech) are two wholly-owned operating subsidiaries of BC Hydro. For more information on Powerex, Powertech, and other active and inactive subsidiaries, see Appendix B: Subsidiaries and Operating Segments.

Report on Performance: Goals, Objectives, and Results

The following goals, objectives and performance measures have been restated from the 2025/26 – 2027/28 service plan. For forward-looking planning information, including current and future performance targets, please see the latest service plan.

Goal 1: Meet growing customer demand

Objective 1.1: BC Hydro will stay close to our customers

As our province continues to grow, so do the needs and expectations of our customers, who we are committed to serving. This objective focuses on engaging deeply with all customer segments to understand their changing needs to effectively power economic growth in British Columbia, including unlocking the economic potential of the North Coast and Northeast areas of the province. It also focuses on finding innovative ways to make life more affordable for British Columbians and help achieve greenhouse gas reduction goals.

Key results

- Achieved a 91 per cent customer satisfaction score based on our quarterly customer surveys.
- Launched an optional residential flat rate on April 1, 2025, as an option for customers with higher electricity use. Depending on usage, customers can save $60 per year.
- Implemented the new Distribution Extension Policy to reduce connection costs for new customers. Customer payments have decreased approximately 10 per cent on average in proportion to total project value since taking effect.
- Worked with the Province to launch the 2026 Call for Demand for Emerging Industries to provide electricity to the AI and data centre sectors, manage rising electricity demand from these fast-growing industries and maintain affordability for ratepayers.
- Signed a Memorandum of Understanding (MOU) with Ksi Lisims LNG confirming interconnection steps to supply up to 600 megawatts of electricity.

Summary of progress made in 2025/26

Enrollment in a growing suite of residential rate options continued to climb in 2025/26. Our optional Residential Time-of-Day rate, launched in June 2024, enables customers to save money by shifting electricity use to off-peak hours, helping to manage peak demand as electricity use grows. This option has been particularly beneficial for electric vehicle owners, who can save between $60 and $125 per year by charging overnight during non-peak times. As of March 31, 2026, 40,850 customers were enrolled. Our optional Residential Flat Rate, launched in 2025/26, offers a single price between Step 1 and Step 2 of the tiered rate structure. The flat rate benefits customers with higher electricity use, including families and households electrifying heating and transportation. Enrollment has been strong, with 64,053 customers enrolled by March 31, 2026. We also eliminated higher electricity rates for residents in 14 off-grid communities this year, most of which are First Nations. These customers now pay the same rates as grid-connected customers. This change reduced annual electricity costs by approximately $160 per household and supports equitable access to affordable electricity across the province. Together, these rate options give customers more flexibility to manage costs and help BC Hydro respond to rising electricity demand.

BC Hydro's Distribution Extension Policy sets out how costs are allocated between customers for new or upgraded connections to our distribution system. The updated policy, which took effect on July 5, 2025, lowers the cost of connections for many customers, speeds up connection timelines, and better balances cost sharing between customers. Most importantly, it provides greater cost certainty for developers and helps to support investments in affordable housing, including larger multi-unit developments as well as electrification of homes and businesses.

To power economic growth across British Columbia, in 2025/26, we worked to modernize how industrial customers connect to our system. Tariff Supplement No. 6 (TS 6) identifies how costs and responsibilities for new infrastructure required to connect a new/increased load to the transmission system are allocated between BC Hydro and the customer. TS 6 plays a critical role in enabling economic development and job growth in British Columbia, by establishing clear, fair and predictable rules for the cost of connecting large transmission customers to the system. It was approved by the BCUC in 1991 and has not been updated since. In February 2025 the BCUC directed BC Hydro to file an application to update TS 6. In 2025/26, BC Hydro advanced work on this application, including conducting workshops with First Nations, industry and other stakeholders, with the intent to file an application with the BCUC in May 2026. BC Hydro also took steps in 2025/26 to improve the interconnection pre-queue process. The improvements focused on ensuring industrial applications were complete and high quality before entering the queue, enabling more efficient processing, clearer information for customers, and reduced rework.

Together, these actions demonstrate BC Hydro’s continued commitment to understanding evolving customer needs, maintaining strong customer satisfaction, and balancing growing demand with affordability, reliability, and long-term public benefit.

Objective 1.2: BC Hydro will deepen our partnerships

We, alongside our customers, work in an increasingly complex economic and operating environment. This objective highlights the need for us to increasingly collaborate with partners, such as municipalities and our suppliers, to develop agile and creative solutions that can accelerate our work, meet growing demand and drive sustainable economic development.

Key results

- Engaged 13 municipalities on their Official Community Plans to better understand future growth to inform and align BC Hydro’s infrastructure planning and investment decisions.

- Expanded use of the capital collaboration tool to support coordination of infrastructure delivery with local governments, resulting in significant cost savings for both local governments and BC Hydro, as well as reducing community disruptions.
- Entered into Master Services Agreements with four contractors to secure electrical construction services for the next 15 years. The agreements secure long-term contractor availability and pricing to support the delivery of BC Hydro's capital plan.

Summary of progress made in 2025/26

As we work to meet growing electricity demand in an increasingly complex environment, we know that working closely with our partners is more important than ever, including with local governments across the province. In 2025/26, this included engaging earlier with municipalities and developers on customer connection processes in the District of Saanich and the City of Victoria, processes to enable overhead connections in the City of Vancouver, and reserving space on site plans early for electrical transformers if needed in the City of Vancouver and City of Victoria. We also launched the Trees & Wires Solutions Lab to enable faster, more cost effective electrical service connections and upgrades while also supporting urban forestry goals through early, cross sector collaboration with local governments and industry partners. Through this partnership, we collaborated with the City of Burnaby to integrate BC Hydro standards into the Master Municipal Construction Documents enabling earlier identification of electrical requirements, reducing revisions, and improving approval success rates. Together, these changes support shorter timelines, lower costs, and more efficient customer connections.

We also worked closely with municipalities this year to jointly plan and deliver infrastructure in ways that minimize community impacts while saving time and money. This included expanding the use of the Capital Collaboration Tool, which overlays BC Hydro and municipal capital plans using geospatial data to identify conflicts, timing overlaps, and coordination opportunities earlier in the planning process. We launched a local government information and support webpage to support collaborative infrastructure planning and faster electrical connections to save time and money, while minimizing impacts to communities. Additionally, we delivered a webinar for local government staff focused on earlier collaboration in housing-related development planning, improving information-sharing, increasing predictability for developers, reducing delays, and supporting smoother approvals.

The supply chain landscape continued to evolve, and we are enhancing the ways we work with suppliers to improve delivery certainty and manage risk. In 2025/26, we advanced development of a collaborative contracting model for major generating equipment such a generators and turbines. When complete, this new model will include long term contracts that will provide certainty for suppliers and reduce BC Hydro's supply chain risk for critical equipment. We also increased the use of early contractor involvement to reduce project risks and improve cost and schedule certainty. This approach leverages the expertise of experienced contractors earlier in the project life cycle. It enhances our collaborative work approach on larger projects by engaging dedicated collaborative coaching services providers to strengthen relationships and a one-team approach to ensure successful delivery of projects.

Performance measure(s) and related discussion

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[1a] CSAT Index[1,2]	92	85	91

Data source: BC Hydro customer satisfaction surveys collected by an independent third-party vendor
[1]PM [1a] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as 85 and 85, respectively.
[2]Percentage of customers satisfied or very satisfied. Customer Satisfaction Index (CSAT) is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial, and industrial). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.

BC Hydro achieved a Customer Satisfaction (CSAT) Index score of 91 in 2025/26, exceeding the target of 85. This result reflects strong performance in meeting customers' electricity and service needs. A stable CSAT target reflects strong baseline service while recognizing that sustained and increasing effort is required to maintain that level as customers' expectations continue to rise. In the near term, BC Hydro does not have any planned investments that would result in a sustained increase to the index.

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[1b] Power Smart Participants[1,2,3]	268,544	215,000	328,277

Data source: Product participation databases
[1]PM [1b] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as 225,000 and 270,000, respectively.
[2]Power Smart Participants includes customer enrolment in the following products: Team Power Smart Challenge, HydroHome, heat pumps, EV Power Management, Peak Saver, Time of Day Rate, and Solar and Battery.
[3]This performance measure was not carried forward into the 2026/27 service plan.

BC Hydro exceeded the 2025/26 target of 215,000 Power Smart Participants, achieving 328,277 participants. This variance was primarily driven by aggressive recruitment of Team Power Smart energy saving challenge participants and higher Peak Saver sign-ups to earn rewards during peak events, reflecting growing customer interest in demand side management programs and fuel switching.

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[1c] Energy Efficiency Program Savings[1,2]	N/A	350	461

Data source: BC Hydro Energy Management and Innovation group
[1]PM [1c] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as 400 and 500, respectively.
[2]Energy Efficiency Program Savings are measured in GWh/year.

BC Hydro delivered 461 gigawatt hours/year from energy efficiency and conservation initiatives, surpassing the 2025/26 Energy Efficiency Program Savings target of 350 gigawatt hours/year. Strong performance was driven largely by the commercial sector, where increased incentives and years of early-stage investment resulted in higher project uptake and savings.

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[1d] GHG Emission Reduction – BC Hydro Operations[1,2]	56	44	56

Data source: Collected by various BC Hydro groups, including: Environment (sulfur hexafluoride (SF6)/CH4); Supply Chain (paper use and air travel); Fleet Services (vehicle emissions); Properties (buildings); Asset Planning (Non-Integrated Areas and Independent Power Producers); and Operations (thermal).
[1]PM [1d] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as 46 and 47, respectively.
[2]Cumulative GHG reductions from BC Hydro operations since 2007. The baseline GHG emission in 2007 was 1,735 k tCO2e.

BC Hydro exceeded the 2025/26 target in accordance with the GHG Management Plan, achieving cumulative reductions of 56 per cent from the 2007 baseline. This was primarily due to the Fort Nelson generating station operating at a lower capacity than forecast, as well as a lower-than-projected carbon intensity at an independent power producer facility. The result has been independently verified by a third party to ensure accuracy.

Goal 2: Strengthen our resilience

Objective 2.1: BC Hydro will invest in B.C.’s energy system

With significant electrical load growth on the horizon, and our existing system aging, this objective reinforces our commitment to extending the life of our assets where possible, while also modernizing and investing in new infrastructure and technology to drive economic development in a way that is responsive to changing market conditions and demand from new large loads. This includes a focus on fostering economic development in northern B.C. through the North Coast Transmission Line and infrastructure to support industrial growth in the Northeast.

Key results

- Advanced critical work to obtain the necessary approvals and permits to begin construction on the North Coast Transmission Line in summer 2026.
- Removed approximately 59,000 trees posing reliability and wildfire risk, including 30,000 hazard trees adjacent to the distribution system and 29,000 edge trees along transmission rights-of-way, which are a combination of hazard trees and encroaching vegetation.
- Established a cloud technology governance model to apply a consistent approach to adopting digital services and new technologies, ensuring faster and more secure adoption.
- Completed the Battery Energy Storage System (BESS) Strategic Framework which, alongside the Capacity Request for Expression of Interest, will help define the path for integrating utility-scale BESS into BC Hydro's grid.

Summary of progress made in 2025/26

In 2025/2026, significant investments were made in major capital infrastructure projects totalling over $1.7 billion, which was a 30 per cent increase over the previous year. During this period, 29 projects were put into service. This included connecting large customer loads to enable economic development and replacing and upgrading aging infrastructure to strengthen the power system across the province. In addition, implementation of new technologies to modernize the grid, such as industry scale battery energy systems, progressed in non-integrated areas to build resilience.

Vegetation that grows too close to BC Hydro's system can lead to power outages and safety risks, which is why we monitor trees and plants near electrical infrastructure and facilities to ensure the system remains safe and reliable. As part of investments in vegetation management across our system, we enhanced our vegetation management capability in 2025/26, launching new province wide satellite imagery capabilities that improves visibility of vegetation risks across the distribution system and enables more targeted, risk-based decision-making.

In 2025/26, we advanced transmission capacity in the North Montney region by transferring 85 km of customer-built 230 kV infrastructure to BC Hydro. These lines will also enable future customer connections, supporting growth in the region. In addition to this, work progressed in 2025/26 with several large North Montney customers to collaborate on the development of a new 100–140 km 230 kV transmission line from BC Hydro's Southbank (Site C) Substation. This approach will reduce cumulative impacts by utilizing a single transmission corridor.

BC Hydro also completed work in 2025/26 to remove 80-year-old H-Frame structures in downtown Vancouver. The work was initiated in 2008, and involved the removal of 355 H-Frames, 368 poles and 346 overhead transformers, spanning more than 80 blocks in the downtown core, replacing them with modern underground systems. This work is an effort to modernize the grid and has improved safety, reliability and aesthetics in some of Vancouver's busiest and most historic neighbourhoods.

Objective 2.2: BC Hydro will secure additional sources of energy and capacity to support a clean economy

Meeting increased demand will require the addition of new sources of renewable energy over a short period of time. This objective emphasizes our efforts to build towards a clean economy by increasing and diversifying B.C.'s energy supply by adding new sources of renewable electricity, while also adding capacity to the system by helping customers adjust their current electricity consumption behaviour.

Key results

- Site C became fully operational in August 2025. The project has capacity to generate more than 1,100 megawatts of electricity, and about 5,000 gigawatt hours of energy each year, enough energy to power about 500,000 homes annually.

- The BCUC accepted the electricity purchase agreements for the 10 successful projects from the 2024 Call for Power, confirming the projects are in the public interest.
- Received 14 proposals from independent power producers totaling more than 9,100 gigawatt hours per year as part of the competitive 2025 Call for Power launched in July 2025.
- Received 106 submissions representing 19 gigawatts of potential new electricity capacity from the 2025 Capacity Request for Expression of Interest (RFEOI), seeking information from organizations capable of delivering cost-effective capacity and/or baseload energy resources.
- Identified partners with market-ready technologies to advance energy efficiency and demand-side management through the Power Smart Solutions RFEOI. Responses to the RFEOI are informing BC Hydro's Power Smart procurement strategies.

Summary of progress made in 2025/26

In 2025/26 BC Hydro continued work to secure new clean electricity resources and prepare the system for rising demand. This included efforts to implement competitive calls for power to secure new renewable generation. The 10 successful projects in the 2024 Call for Power are expected to generate approximately 4,830 gigawatt hours of electricity annually. That is enough to power half a million new homes, increasing BC Hydro's supply by 8 per cent. In addition, the strong response to the 2025 Call for Power demonstrated significant market readiness to meet rising electricity demand with new clean and renewable energy projects.

This year we also issued the Capacity RFEOI to gather information from the market on potential future sources of firm and reliable capacity. While the RFEOI was an information gathering exercise and did not result in electricity purchase agreements, it confirmed strong market interest in advancing capacity solutions across technologies and regions. The RFEOI is a tool to identify opportunities and guide strategic planning and is part of a larger strategy to prepare for rising demand. In 2025/26, BC Hydro also advanced the addition of a sixth generating unit at the Revelstoke Generating Station, which will add an additional 500 megawatts of capacity, as well as upgrades at the G.M. Shrum Generating Station, which will add another 100 megawatts of capacity to the system.

Energy efficiency and demand response continue to be some of the lowest cost ways to secure system capacity and help manage growing demand. BC Hydro's Peak Saver program saw a surge in participation this year, with more than 150,000 residential customers now participating. In 2025, 116,000 British Columbians took on a Team Power Smart energy-saving challenge to reduce their household electricity consumption by 10 per cent, resulting in 30 gigawatt hours of energy savings. We also advanced innovative demand-side solutions through pilot programs within a virtual power plant. The pilot included the installation of 200 residential batteries in homes in Sun Peaks and Harrison Mills, allowing stored energy to be used during peak demand periods and providing backup power during outages.

Objective 2.3: BC Hydro will empower and strengthen our organization

BC Hydro provides stable, family supporting jobs, across British Columbia. The increasing scale, scope and complexity of work will have significant impacts on our people and organization. This objective highlights the need to increase our emphasis on innovation and technology in our business, ensure we have the skills needed for the future, and take an intentional approach to supporting the workplace culture we need to succeed.

Key results

- No employee fatalities or permanently disabling injuries in 2025/26.
- Established a Workplace Culture Champions network, enabling approximately 250 employees as early adopters to model desired behaviours and influence culture change across the organization.
- Advanced the strategic use of coaching to support leadership effectiveness, engaging over 200 leaders across the company to help strengthen new leadership behaviours to improve team performance and delivery outcomes.
- Improved connectivity for field and remote workers by deploying satellite technology. This enables work to be carried out efficiently in locations previously limited by network access, particularly in rural and emergency situations.
- Expanded access to AI assistant technology to enable employees to make use of low-risk AI tools to achieve efficiencies and increase their ability to deliver on an expanding body of work.

Summary of progress made in 2025/26

Safety is at the core of everything we do at BC Hydro and remains foundational to how we operate and deliver for British Columbians. In 2025/26, we developed the Serious Incident Management (SIM) Process and Standard as part of the downtown Vancouver vault explosion corrective actions. These actions strengthen how we learn from serious and potentially serious incidents and enhance safety for workers and the public. The SIM process brings a standardized, more consistent focus to near miss and potentially serious public safety incidents. This year, through application of the SIM process, we investigated a broader range of incidents with greater frequency and rigour, ensured independent investigations, applied a more formal approach to corrective action development, and increased senior leadership transparency and follow up.

In 2025/26, we worked to strengthen leadership capability across the organization. A range of leadership and professional development initiatives supported employees at different stages of their careers, from aspiring leaders and those new to leadership roles, to experienced leaders expanding their capabilities. These efforts reached thousands of employees through leadership forums, targeted learning campaigns, expanded leadership development journeys, and a broad portfolio of professional development courses. Together, this approach helped strengthen leadership depth, support consistent leadership behaviours, and enhance the organization's capacity to deliver an increasingly complex body of work.

In parallel, targeted technology investments, including the role of AI, are improving how work is carried out across the organization. In one example, as we work towards delivering our capital plan, we have identified strategic AI use cases to improve project delivery efficiency, with initial AI pilots in contract change validation and drafting showing potential for time savings. Together, these efforts helped ensure our organization remains resilient, agile, and well positioned to meet future challenges.

Performance measure(s) and related discussion

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[2a] Fatality & Permanently Disabling Injury[1,2]	0	0	0

Data source: BC Hydro Incident Management System
[1]PM [2a] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as 0 and 0, respectively.
[2]Loss of life or the injury has resulted in a permanent disability. BC Hydro's safety performance measure does not include contractor or public safety injuries or fatalities.

In 2025/26, BC Hydro achieved its performance target of zero fatalities and permanently disabling injuries among employees. BC Hydro continues to strengthen its safety management system through ongoing training, incident analysis, and proactive risk mitigation initiatives.

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[2b] System Average Interruption Duration Index (SAIDI)[1,2,3,4]	3.67	4.50	4.61

Data source: BC Hydro Distribution Outage Data Warehouse System and Asset Registry
[1]PM [2b] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as 4.55 and 4.55, respectively.
[2]Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the reliability projection modelling uncertainty, the wide range of variations in weather patterns, and the uncontrollable elements that can significantly disrupt the electrical system. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.
[3]Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year excluding major events.
[4]In 2025/26, BC Hydro adopted the Institute of Electrical and Electronics Engineers (IEEE) standard of a major event day. The 2024/25 actual above reflects the results prior to the adoption of the IEEE standard. The 2024/25 result under the IEEE standard is 4.93.

The 2025/26 SAIDI result was 2.4 per cent above the target of 4.50 primarily due to tree-related and planned outages. However, the variance is within the allowable range of 10 per cent so the target is considered met. Performance within 10 per cent is considered acceptable given the estimation uncertainty, the wide range of variations in weather patterns and uncontrollable elements that can significantly disrupt the electrical system.

Performance Measure	2023/24 Actual	2025/26 Target	2025/26 Actual
[2c] Employee Engagement Index (points)[1,2]	74	At or above the engagement score of the BC Public Service	N/A

Data source: Confidential biennial employee engagement survey administered by an external service provider.
[1]PM [2c] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as at or above the engagement score of the BC Public Service.
[2]At or above the score of the BC Public Service, which was 70 points in 2024.

No Employee Engagement Index result is reported for 2025/26, as the biennial employee engagement survey was not administered due to labour disruptions affecting the BC Public Service, our external survey provider. The most recent completed survey in 2023/24 resulted in a score of 74, exceeding the BC Public Service benchmark.

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[2d] Cybersecurity Ranking amongst Canadian Peers[1,2]	Upper quartile	Upper quartile	Upper quartile

Data source: BitSight Security Rankings Amongst Canadian Peers
[1]PM [2d] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as Upper quartile.
[2]The 11 Canadian peers BC Hydro is benchmarked against includes: SaskPower, Hydro One, TransAlta, Nova Scotia Power, Hydro-Quebec, NB Power, Manitoba Hydro, Nalcor Energy, Atco Ltd., Northwest Territories Power Corporation, and Ontario Power Generation.

BC Hydro met its 2025/26 target of achieving an upper quartile ranking among Canadian peers for cybersecurity performance. The Cybersecurity Ranking Amongst Canadian Peers is an industry-recognized measure of preparedness to withstand cybersecurity incidents.

Goal 3: Maintain affordability

Objective 3.1: BC Hydro will ensure long-term financial sustainability

A lot is changing, and this objective ensures our financial model and structures are set up to deliver the needed investments in our system both today and in the longer-term. Managing costs and improving operational efficiencies with technology and process optimization will remain important to ensure we can continue to meet demand and support economic development in British Columbia.

Key results

- Implemented a rate increase of 3.75 per cent for 2025/2026, supporting forecast costs and capital investments, while maintaining BC Hydro rates as one of the lowest in North America.
- Achieved the fiscal 2026 net income plan while managing cost pressures during the year through reprioritization and efficiencies.

- Financial forecasts include supporting economic development and powering the economy, while managing our costs and ensuring long-term financial sustainability.
- Launched an AI Literacy Program to equip employees with the foundational knowledge to understand, use, and apply AI responsibly to deliver our work more efficiently.

Summary of progress made in 2025/26

On March 17, 2025, the Province submitted a rate stability direction to the BCUC to set BC Hydro's annual average rate increase at 3.75 per cent for 2025/2026 and 2026/2027. The first increase took effect on April 1, 2025.The rate increase balances affordability with needed investments in B.C.'s power system. In Hydro Quebec's 2025 Rate Comparison Report, BC Hydro's rates are among the lowest in North America. BC Hydro's residential, commercial and industrial rates are the third-lowest surveyed.

Performance measure(s) and related discussion

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[3a] Affordable Bills – Residential [1,2]	1st quartile	1st quartile	1st quartile

Data source: Hydro-Québec's annual report on North American electricity rates, "Comparison of Electricity Prices in Major North American Cities"

[1]PM [3a] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as 1st quartile.

[2]BC Hydro calculates the Affordable Bills performance measure based on the median consumption level for residential customer. The rankings of the 22 participating utilities are then allocated into quartiles. The 1st quartile ranking represents the six utilities that have the lowest monthly electricity bills on April 1 of a given year.

BC Hydro maintained its 2025/26 target of first quartile ranking for residential electricity rates among North American utilities, based on analysis of Hydro Québec's annual rate comparison report. BC Hydro balances affordability for customers with significant required investment in the electricity system, including operating and capital expenditures that support safety and reliable service.

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[3b] Project Budget to Actual Cost: Cumulative Five Years (% variance] [1,2,3]	+2.29	Within ±5% of budget	+3.86

Data source: BC Hydro Capital Infrastructure Project Delivery

[1]PM [3b] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as within ± 5% of budget.

[2]This measure compares actual project costs at completion to the original approved expected cost budget for the project, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period.

[2]Site C is not included in this measure because the size of the Site C Project would dominate the results of this measure making the results less meaningful.

BC Hydro has consistently met its yearly target of being within ±5 per cent of the project budget, excluding project reserve amounts. Over the last five years, BC Hydro successfully delivered 226 capital projects at a total cost of $3.019 billion, which is 3.86 per cent above the aggregated budget of $2.907 billion and within the target of ±5 per cent of budget.

Goal 4: Advance reconciliation with First Nations

Objective 4.1: BC Hydro will continue to invest in and build mutually beneficial and stronger relationships with First Nations communities

Constructing and operating our electricity system has left lasting impacts on Indigenous peoples, cultures, traditions and ways of life, which we deeply regret. Developing mutually beneficial relationships with First Nations is critical to our ongoing approach to operating and growing our system.

Key results

- Reached, renewed, or extended Relationship Agreements with seven First Nations to create sustainable benefits with the Nations through procurement and other interests.
- 96 per cent of all BC Hydro employees have completed BC Hydro's Indigenous awareness courses as of March 31, 2026.
- Completed the final phase of engagement with non-integrated areas (NIA) Nations on the NIA Strategy.
- Consulted with First Nations to collect feedback on the draft 2025 Integrated Resource Plan, which was submitted to the BCUC in fall 2025.

Summary of progress made in 2025/26

In 2025/26 we adapted and expanded our Indigenous employment and training programs to better align with business needs while creating new pathways for participation. Following a successful pilot program, the Try-A-Trade program launched as a permanent program in 2025/26. The program offers Indigenous candidates the chance to try two different BC Hydro trades through a 16-week paid work experience program, and this year, was broadened to include additional trades. The Indigenous Professionals in Development program offers Indigenous professionals paid work and professional development placements at BC Hydro. This year, we focused on recruiting candidates in professions aligned with our future anticipated workforce needs. Eleven participants were hired into roles within BC Hydro outside of the two programs in 2025/26.

In 2025/26, meaningful engagement with First Nations continued to inform long-term system planning. As part of the development of the 2025 Integrated Resource Plan (IRP), BC Hydro continued a multi-phase consultation process during the spring and summer of 2025. All First Nations and Tribal Councils in the province were invited to participate, and feedback gathered helped shape development of the 2025 IRP.

Since 2018, BC Hydro has worked with NIA Nations to reduce reliance on diesel generation and support more sustainable energy solutions. After three phases of engagement, engagement on the NIA strategy was completed in 2025/26, with the intent to publish the final NIA strategy document in June 2026.

Collectively, these efforts demonstrate continued progress toward integrating reconciliation into BC Hydro's planning, operations, and people practices. BC Hydro remains committed to building respectful, collaborative, and enduring relationships with First Nations that support shared objectives, meaningful participation, and the responsible growth of the electricity system.

Objective 4.2: BC Hydro will increase First Nations participation in the energy system

This objective highlights the important role we have to play in advancing reconciliation, and our belief that new models of doing business will be critical moving forward. To be successful we need to continue building on our relationship with First Nations and look for opportunities for First Nations to become partners in the energy system.

Key results

- The 2025 Call for Power included a 25 per cent First Nations equity ownership requirement, with the option of higher equity levels, and incentivised additional benefits outside of equity ownership.
- Brought Solar North, an Indigenous owned and operated solar plant in Masset, into commercial operation under a 20-year Community Energy Purchase Agreement.
- Reached Declaration of Compatibility to Operate for the Ulkatcho First Nation-owned Anahim Lake solar farm, enabling safe connection to BC Hydro's system.
- Advanced construction on a Battery Energy Storage System and microgrid controller at Anahim Lake, alongside Ulkatcho Energy Corporation, which will enable efficient storage and distribution of power from the Anahim Lake Solar Farm.
- Signed term sheets or deal sheet agreements for North Coast Transmission Line Phase 1 and 2 with 12 of 14 Nations and all eight Hereditary Chiefs of the Wet'suwet'en Nation, laying the foundation for comprehensive legal partnerships.

Summary of progress made in 2025/26

In 2025/26, we took significant steps towards increasing First Nations participation in the energy system. In addition to the First Nations equity ownership requirements for the 2025 Call for Power, the 30-year electricity purchase agreements for 10 successful 2024 Call for Power projects were accepted by the BCUC. Across these projects, First Nations equity ownership was between 49-51 per cent and together will represent up to $3 billion of asset ownership by First Nations.

Solar North, located in Masset, is British Columbia's first Indigenous owned and operated solar plant located in a non-integrated area. The solar plant began supplying power on December 5, 2025, delivering clean electricity to BC Hydro's Masset microgrid under a 20-year Community Energy Purchase Agreement with BC Hydro. This is a meaningful step towards reducing diesel reliance in remote communities.

The Ulkatcho First Nation-owned Solar Farm in Anahim Lake achieved a significant milestone in 2025/26 by reaching Declaration of Compatibility to Operate, which is a critical step to ensure it meets the technical, safety, and operational requirements needed to connect to BC Hydro's microgrid. BC Hydro's work in 2025/26 to enable the efficient storage and distribution of solar energy from the facility will support reduced diesel use, lower greenhouse gas emissions, and improved reliability. These upgrades will also allow surplus daytime energy to be stored and used when needed, ensuring a stable power supply, even at night. The project is forecast to be fully operational in fall 2026.

In addition to the term sheets or deal sheet agreements signed with First Nations for Phase 1 and 2 of the North Coast Transmission Line, which are mentioned above, BC Hydro continued engagement with nine potentially affected First Nations for Phase 3 of the transmission line.

Performance measure(s) and related discussion

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[4a] First Nations Economic Participation[1,2,3]: • Economic Participants (#) • First Nations Revenues ($ million)	 N/A N/A	 Info Only 250	 275 $439.3

Data source: BC Hydro Supply Chain, Independent Power Producer Portfolio Management, and Properties
[1]PM [4a] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as Info only for Economic Participants, and 550 and 800, respectively, for First Nations Revenues.
[2] Economic Participants counts the number of instances of First Nations participation in directed Indigenous procurement contracts, Indigenous land lease contracts, Electricity Purchase Agreements with Indigenous equity interest, and Indigenous joint ownership of transmission assets.
[3] First Nations Revenues measures the total cumulative value paid to First Nations beginning in 2025/26 for directed Indigenous procurement contracts, Indigenous land lease contracts, Electricity Purchase Agreements with Indigenous equity interest, and Indigenous joint ownership of transmission assets.

BC Hydro exceeded its 2025/26 target for First Nations Revenues, which measures the total cumulative value paid to First Nations beginning in 2025/26 for directed Indigenous procurement contracts, Indigenous land lease contracts, Electricity Purchase Agreements with Indigenous equity interest, and Indigenous joint ownership of transmission assets, achieving $439.3 million. First Nations Economic Participation is a proxy for the ability to become partners in the energy system with the First Nations and a commitment to advancing meaningful economic reconciliation with First Nations.

Performance Measure	2024/25 Actual	2025/26 Target	2025/26 Actual
[4b] Partnership Accreditation in Indigenous Relations [1]	Gold	Gold	Gold

Data source: The Partnership Accreditation in Indigenous Relations certification program is overseen by the Canadian Council for Aboriginal Business. It is reviewed on a three-year cycle. BC Hydro last received the three-year Gold accreditation in 2024/25.
[1]PM [4b] targets for 2026/27 and 2027/28 were stated in the 2025/26 service plan as Gold.

BC Hydro maintained its Gold Certification under the Partnership Accreditation in Indigenous Relations (PAIR) program, meeting the 2025/26 target. This certification reflects BC Hydro's continued commitment to advancing leading reconciliation practices across the areas of leadership, community relationships, business development, and employment. PAIR certification is awarded following independent assessment by the Canadian Council for Aboriginal Business and is reviewed on a three-year cycle, providing external validation of BC Hydro's reconciliation practices.

Financial Report

For the auditor's report and audited financial statements, see Appendix C. These documents can also be found on the BC Hydro website.

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the year ended March 31, 2026 and should be read in conjunction with the 2025/26 Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2026 and 2025.

All financial information is expressed in Canadian dollars unless otherwise specified.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

Highlights

- Net income for the year ended March 31, 2026 was $721 million, $134 million (or 23 per cent) higher than the net income of $587 million in the prior fiscal year. The increase was primarily driven by lower finance charges, higher revenues, and higher net movement in regulatory account balances (i.e., higher net deferred amounts which results in higher net income), partially offset by higher operating expenses.
- Total revenue for the year ended March 31, 2026 was $7.59 billion, $116 million (or 2 per cent) higher than the prior fiscal year, primarily as a result of higher domestic revenues, partially offset by lower trade revenues. Domestic revenues were higher as a result of a combination of average customer rate increases of 3.75 per cent directed by Government and approved by the British Columbia Utilities Commission (BCUC) effective April 1, 2025 and a 3 per cent increase in sales volumes. Trade revenues were lower due to lower average sales prices.
- Energy costs for the year ended March 31, 2026 were $2.75 billion, $115 million (or 4 per cent) lower than the prior fiscal year. The lower energy costs were primarily due to a decrease in market purchases mainly driven by lower electricity import costs as a result of lower volumes. Net electricity import volumes for the year ended March 31, 2026 were 4,344 GWh, 4,012 GWh (or 48 per cent) lower than the prior fiscal year of 8,356 GWh primarily due to better water conditions and the addition of Site C generation. The decrease in energy costs also reflects lower transmission costs related to trading activity. The decrease in costs was partially offset by higher purchases from Independent Power Producers (IPPs).

- Water inflows (energy equivalent) to the system for the year ended March 31, 2026 were below the historical average, although higher than the prior fiscal year. The below average water inflows for the current fiscal year were primarily driven by the below average snowpack in the spring of 2025. Despite this, as at March 31, 2026, system energy storage was tracking above the ten-year historical average and higher than March 31, 2025 due to net imports and greater total inflows.
- Capital expenditure investments, before contributions in aid of construction, for the year ended March 31, 2026 were $3.93 billion, a $88 million decrease compared to the prior fiscal year. The decrease was primarily due to lower Site C Project expenditures as major scopes of work were completed in the prior fiscal year. The decrease was partially offset by higher capital expenditure investments for transmission and generation to expand the electricity system to meet future demand as well as other investments to renew our existing infrastructure.

  During the year ended March 31, 2026, capital expenditure investments transferred to assets in-service were $3.15 billion compared to $14.90 billion in the prior fiscal year, with the decrease primarily due to $13.20 billion of Site C Project expenditures placed in-service in the prior fiscal year.
- The net regulatory asset balance as at March 31, 2026 was $2.77 billion, a $254 million increase compared to $2.52 billion as at March 31, 2025.

Consolidated Results of Operations

for the years ended March 31 ($ in millions)	**2026**	2025	Change
Total Revenues	**$ 7,594**	$ 7,478	$ 116
Operating Expenses	**$ 6,690**	$ 6,399	$ 291
Finance Charges	**$ 864**	$ 1,094	$ (230)
Net movement in regulatory balances	**$ 681**	$ 602	$ 79
Net Income	**$ 721**	$ 587	$ 134
Capital Expenditure Investments	**$ 3,927**	$ 4,015	$ (88)
GWh Sold (Domestic)	**58,371**	56,754	1,617

($ in millions)	***As at March 31, 2026***	*As at March 31, 2025*	Change
Total Assets and Regulatory Balances	**$ 54,666**	$ 53,178	$ 1,488
Shareholder's Equity	**$ 8,990**	$ 8,254	$ 736
Net Debt	**$ 34,404**	$ 32,049	$ 2,355
Debt to Equity	**79 : 21**	80 : 20	n/a
Number of Domestic Customer Accounts	**2,301,508**	2,256,615	44,893

Revenues

For the year ended March 31, 2026, total revenues of $7.59 billion, were $116 million (2 per cent) higher than the prior fiscal year. The increase was due to higher domestic revenues of $301 million, partially offset by lower trade revenues of $185 million.

	($ in millions)		*(gigawatt hours)*	
for the twelve months ended March 31	**2026**	2025	**2026**	2025
Revenues				
Residential	**$ 2,490**	$ 2,405	**19,371**	19,345
Light industrial and commercial	**2,143**	2,061	**19,406**	19,319
Large industrial	**1,026**	947	**15,132**	14,482
Other sales	**691**	636	**4,462**	3,608
Domestic Revenues	**6,350**	6,049	**58,371**	56,754
Trade Revenues[1]	**1,244**	1,429	**23,796**	21,787
Revenues	**$ 7,594**	$ 7,478	**82,167**	78,541

[1]In accordance with IFRS 9, Financial Instruments, certain energy costs are reclassified to trade revenue and netted against revenues which reduces trade revenues.

Domestic Revenues

For the year ended March 31, 2026, domestic revenues were $6.35 billion, $301 million (or 5 per cent) higher than the prior fiscal year. The increase was due to a 3.75 per cent bill increase directed by Government and approved by the BCUC effective April 1, 2025, and higher domestic sales volumes compared to the prior fiscal year.

Domestic sales volumes were 1,617 GWh (or 3 per cent) higher than the prior fiscal year. Excluding electricity exports (included in Other Sales), domestic sales volumes were 730 GWh (or 1 per cent) higher than the prior fiscal year.

Trade Revenues

For the year ended March 31, 2026, trade revenues were $1.24 billion, a decrease of $185 million (or 13 per cent), compared to the prior fiscal year. The decrease was primarily driven by lower average sales prices.

Operating Expenses

Operating expenses for financial statement purposes include energy costs (electricity and gas purchases, water rentals, transmission charges), amortization and depreciation, operational costs (materials and external services and personnel costs), and other costs, net of capitalized costs. For the year ended March 31, 2026, total operating expenses of $6.69 billion were $291 million (or 5 per cent) higher than the prior fiscal year. The increase was primarily due to higher amortization and depreciation expenses of $154 million, higher materials and external services costs of $117 million, higher personnel expenses of $63 million, and higher other costs, net of recoveries of $65 million, partially offset by lower energy costs of $115 million.

Energy Costs

Energy costs are comprised of electricity and gas purchases, water rentals and transmission charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, and energy demand.

	($ in millions)		*(gigawatt hours)*	
for the twelve months ended March 31	**2026**	2025	**2026**	2025
Energy Costs				
Purchases from Independent Power Producers	**$ 1,414**	$ 1,257	**14,219**	12,920
Market purchases[1]	**657**	861	**30,122**	30,865
Non-Treaty storage and Co-ordination ɟreements	**-**	37	**-**	-
Other expenses	**47**	54	**124**	120
Electricity and gas purchases	**2,118**	2,209	**44,465**	43,905
Water rental payments (hydro generation)[2]	**336**	294	**42,988**	39,734
Transmission charges	**295**	361	**-**	-
Energy Costs	**$ 2,749**	$ 2,864	**87,453**	83,639

[1]Market purchases are comprised of the cost of importing energy to meet domestic load requirements and energy costs associated with BC Hydro's energy trading subsidiary, Powerex. Market purchases include physical and financial transaction costs whereas the volumes only include physical transactions.

[2]Water rental payments are based on the previous calendar year's actual hydro generation volumes and the volumes reported in this table are based on actual fiscal year hydro generation volumes.

Energy costs for the year ended March 31, 2026 were $2.75 billion, $115 million (or 4 per cent) lower than the prior fiscal year.

Electricity and gas purchases for the year ended March 31, 2026 were $2.12 billion, $91 million (or 4 per cent) lower than the prior fiscal year. The decrease in costs was primarily due to a decrease in market purchases, mainly driven by lower imports of electricity compared to the prior fiscal year. Net electricity import volumes for the year ended March 31, 2026 were 4,344 GWh, 4,012 GWh (or 48 per cent) lower than the prior fiscal year of 8,356 GWh primarily due to better water conditions and the addition of Site C generation. The decrease in Non-Treaty storage and co-ordination agreement costs was due to one agreement that expired and the other had no activity during the year. The decrease in costs was partially offset by higher purchases from Independent Power Producers (IPPs) largely due to higher deliveries to BC Hydro from IPPs as prior deliveries were lower due to low inflows from the drought conditions and outages.

Water rental payments for the year ended March 31, 2026 were $336 million, $42 million (or 14 per cent) higher than the prior fiscal year. Water rental payments are based on the prior calendar year's hydro generation volumes, and hydro generation volumes were higher in calendar 2024 compared to calendar 2023 due to higher water inflows.

Transmission charges for the year ended March 31, 2026 were $295 million, $66 million (or 18 per cent) lower than the prior fiscal year primarily due to lower transmission costs related to trading activity.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system for the year ended March 31, 2026 were below the historical average, although higher than the prior fiscal year. The below average inflows for the current fiscal year were primarily driven by the below average snowpack in the spring of 2025.

Despite this, as at March 31, 2026, system energy storage was tracking above the ten-year historic average and higher than March 31, 2025 due to net imports and greater total inflows.

Variability in inflows, Electricity Purchase Agreement deliveries, domestic load, operation of storage reservoirs, and generating unit and transmission outages can all impact whether BC Hydro is a net importer or exporter of electricity in any given year. BC Hydro has been a net exporter of electricity in 8 of the previous 15 fiscal years.

Personnel Expenses

Personnel expenses include salaries, wages, and benefits for employees that deliver operational activities and programs, support capital projects and programs, and post-employment benefits. Personnel expenses for the year ended March 31, 2026 were $979 million, $63 million (or 7 per cent) higher than the prior fiscal year due to additional employees primarily delivering increased capital project and operational maintenance work, higher current service pension costs attributed to lower pension discount rates which are based on rates at the beginning of the year and the increase in employees, and compensation increases commensurate to the public sector mandate.

Materials and External Services

Materials and External Services primarily include materials, supplies, and contractor fees to deliver operational requirements, support capital projects, capital other programs such as Demand-Side Management and Demand-Side Management programs. Materials and external services for the year ended March 31, 2026 were $1.22 billion, $117 million (or 11 per cent) higher than the prior fiscal year primarily due to higher costs incurred on Demand-Side Management, higher technology costs, higher maintenance costs, partially offset by a decrease in rebates for electric vehicles provided by BC Hydro.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and depreciation of right-of-use assets. Amortization and depreciation expense for the year ended March 31, 2026 were $1.35 billion,

$154 million (or 13 per cent) higher than the prior fiscal year primarily due to higher depreciation of the Site C Project assets, including the dam, powerhouse, and all six generating units, that are now fully in-service, which were either in-service for a portion of the prior fiscal year or not yet fully in-service.

Grants and Taxes

The Company is a Crown corporation and therefore no Canadian provincial or federal income tax is payable. However, the Company pays provincial and local government taxes and grants in lieu of property taxes to municipalities, regional districts, and rural area jurisdictions. In addition, Powerex, a subsidiary of BC Hydro, pays taxes relating to trading activity in the United States.

Total grants and taxes for the year ended March 31, 2026 were $336 million, which is comparable to $326 million in the prior fiscal year.

Other Costs, net of Recoveries

Other costs, net of recoveries primarily includes environmental provisions for the remediation of polychlorinated biphenyl (PCB) and asbestos, gains and losses on the disposal of assets, certain cost recoveries related to operating costs, and dismantling costs.

Other costs net of recoveries for the year ended March 31, 2026, were $163 million, $65 million (or 66 per cent) higher than the prior fiscal year primarily due to an increase in dismantling costs for future decommissioning work on leased land and higher write-offs of capitalized project costs.

Capitalized Costs

Capitalized costs include costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the year ended March 31, 2026 were $108 million, which is comparable to the $105 million in the prior fiscal year.

Finance Charges

Finance charges for the year ended March 31, 2026 were $864 million, a decrease of $230 million (or 21 per cent) compared to the prior fiscal year. This was primarily due to gains on interest rate hedges used to economically hedge the interest rates on future debt issuances in the current fiscal year as compared to losses in the prior fiscal year. The decrease was partially offset by lower capitalization of interest mainly due to Site C as a large portion of its assets are now in-service.

Regulatory Transfers

In accordance with International Financial Reporting Standard (IFRS) 14, *Regulatory Deferral Accounts*, the Company separately presents regulatory balances and related net movements on the Consolidated Statements of Financial Position and the Consolidated Statements of Comprehensive Income.

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, including to better match costs and benefits for different generations of customers, and to defer differences between forecast and actual costs or revenues to future periods. Deferred amounts are included in customer rates in future periods, subject to approval by the BCUC, and have the effect of adjusting net income.

Net regulatory account transfers are comprised of the following:

for the years ended March 31 (in millions)	**2026**	2025
Cost of Energy Variance Accounts		
Heritage Deferral Account	**$ 55**	$ 106
Non-Heritage Deferral Account	**65**	187
Load Variance	**123**	75
Biomass Energy Program Variance	**46**	(36)
Low Carbon Fuel Credits Variance	**15**	(9)
	304	323
Other Cash Variance Accounts		
Trade Income Deferral Account	**167**	(55)
Total Finance Charges	**(56)**	39
Inflationary Pressures	**-**	104
Electrical Vehicle Rebate	**(30)**	54
Project Write-off Costs	**19**	8
Remediation	**26**	40
Site C Variance Costs	**15**	115
Other	**72**	95
	213	400
Non-Cash Variance Accounts		
Non-Current Pension Costs	**(344)**	191
PEB Current Pension Costs	**-**	(28)
Debt Management	**(300)**	165
Other	**-**	4
	(644)	332
Benefit Matching Accounts		
Demand-Side Management	**240**	186
First Nations Costs	**16**	17
Site C	**1**	(4)
CIA Amortization	**(5)**	(5)
Cloud Costs	**80**	61
Other	**(89)**	3
	243	258

Non-Cash Provisions		
Environmental Provisions	**(28)**	(29)
First Nations Provisions	**3**	4
	(25)	(25)
Rate Smoothing Accounts		
Rate Smoothing	**1**	(438)
Amortization of regulatory accounts	**136**	(188)
Interest on regulatory accounts	**26**	6
Net increase in regulatory accounts	**$ 254**	$ 668

For the year ended March 31, 2026, there was a net increase of $254 million (or 10%) to the Company's regulatory accounts compared to a net increase of $668 million in the prior fiscal year. The net regulatory asset balance as at March 31, 2026 was $2.77 billion compared to $2.52 billion as at March 31, 2025.

Significant changes to the net regulatory asset balance during the year ended March 31, 2026 included:

- $304 million addition to the Cost of Energy Variance Accounts primarily due to net electricity imports as compared to planned net electricity exports, and lower domestic sales volumes compared to plan;
- $240 million addition to the Demand-Side Management Account for expenditures;
- $167 million addition to the Trade Income Deferral Account primarily as a result of lower than planned trade income;
- $136 million of amortization of regulatory accounts with amounts owing to ratepayers (which is the regulatory mechanism to recover the regulatory account balance in rates);

Partially offset by:

- $344 million reduction to Non-Current Pension Costs Account primarily due to higher discount rates at the end of the year compared to plan, and higher asset returns; and
- $300 million reduction to the Debt Management Account primarily due to a net increase in the fair value of interest rate hedges resulting from an increase in forward interest rates.

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2026**	2025
Cost of Energy Variance Accounts		
Heritage Deferral Account	**$ 106**	$ 167
Non-Heritage Deferral Account	**513**	1,494
Load Variance	**151**	88
Biomass Energy Program Variance	**(10)**	(188)
Low Carbon Fuel Credits Variance	**(10)**	(84)
	750	1,477

Other Cash Variance Accounts		
Trade Income Deferral Account	**(385)**	(1,856)
Total Finance Charges	**(31)**	115
Inflationary Pressures	**57**	113
Electrical Vehicle Rebate	**(49)**	(18)
Project Write-off Costs	**53**	55
Remediation	**11**	17
Site C Variance Costs	**137**	117
Other	**155**	133
	(52)	(1,324)
Non-Cash Variance Accounts		
Non-Current Pension Costs	**(1,042)**	(730)
PEB Current Pension Costs	**(43)**	(85)
Debt Management	**(256)**	33
Other	**13**	13
	(1,328)	(769)
Benefit Matching Accounts		
Demand-Side Management	**1,055**	936
First Nations Costs	**2**	3
Site C	**507**	511
CIA Amortization	**48**	53
Smart Metering & Infrastructure	**66**	88
Cloud Costs	**178**	111
Other	**(16)**	2
	1,840	1,704
Non-Cash Provisions		
Environmental Provisions	**162**	190
First Nations Provisions	**478**	476
	640	666
Rate Smoothing Accounts		
Rate Smoothing	**(219)**	(446)
	(219)	(446)
IFRS Transition Accounts		
IFRS Pension	**230**	268
IFRS Property, Plant & Equipment	**913**	944
	1,143	1,212
Net Regulatory Assets	**$ 2,774**	$ 2,520

BC Hydro has BCUC-approved regulatory mechanisms to fully collect 40 of 43 regulatory accounts at March 31, 2026 in rates over various periods. For the remaining 3 regulatory accounts (Electric Vehicle Public Charging, Electric Vehicle Rebate and Site C Variance Costs), BC Hydro will apply for a recovery mechanism at a future date.

Comparison with Service Plan

The *Budget Transparency and Accountability Act* requires that BC Hydro file a service plan each year. BC Hydro's 2025/26-2027/28 Service Plan (Service Plan) was filed in March 2025 with planned net income for 2025/26 of $712 million.

The table below provides an overview of BC Hydro's 2025/26 financial results, relative to its Service Plan.

(in millions)	**Actual**	**Service Plan**	**Variance to Service Plan**
For the year ended March 31,	**2026**	**2026**	
Revenues			
Domestic	$ 6,350	$ 6,764	$ (414)
Trade	1,244	1,375	(131)
	7,594	8,139	(545)
Expenses			
Operating Costs			
Cost of energy	2,749	2,862	113
Other operating expenses			
Personnel expenses, materials and external services [1]	2,049	2,026	(23)
Amortization	1,354	1,357	3
Grants and taxes	336	360	24
Other	202	134	(68)
Finance charges	864	1,121	257
	7,554	7,860	306
Net Income Before Movement in Regulatory Balances	40	279	(239)
Net movement in regulatory balances	681	433	248
Net Income	$ 721	$ 712	$ 9

Net income for 2025/26 was $721 million, slightly better than the planned net income of $712 million in the Service Plan filed in March 2025. Many variances, including those related to revenues, cost of energy, amortization, finance charges and others are deferred to regulatory accounts pursuant to BCUC orders, and do not impact net income.

Forecast net income for 2025/26 in BC Hydro's 2026/27 – 2028/29 Service Plan filed in February 2026 was $712 million, and actual net income was slightly higher than the forecast.

Liquidity and Capital Resources

Cash flow provided by operating activities for the year ended March 31, 2026 was $1.33 billion, compared to $806 million in the prior fiscal year. The increase was primarily due to higher cash from changes in working capital.

Net debt as at March 31, 2026 was $34.40 billion compared to $32.05 billion as at March 31, 2025. The increase was mainly a result of net proceeds from short-term borrowings of $1.27 billion, issuances of long-term bonds for net proceeds of $900 million (net of redemptions) and a sinking fund maturity of $225 million. These increases were primarily to fund capital expenditure investments and to manage working capital.

As at March 31, 2026, the Company had a working capital deficit of $5.86 billion which is primarily due to its commercial paper borrowing program. The working capital deficit is considered to be in the normal course of business where the Company has access to revolving credit facilities and debt issuances through the Province to manage cash flow requirements and does not impact operations.

Capital Expenditure Investments

Capital expenditure investments include property, plant and equipment and intangible assets. Capital expenditures, before contributions in aid of construction, were as follows:

for the years ended March 31 (in millions)		**2026**		2025
Transmission lines and substations replacements and expansion	**$**	**1,208**	$	874
Generation replacements and expansion		**778**		631
Distribution system improvements and expansion		**968**		940
General, including technology, vehicles and buildings		**437**		326
Site C Project		**536**		1,244
Capital Expenditure Investments	**$**	**3,927**	$	4,015

Capital expenditure investments for the year ended March 31, 2026 were $3.93 billion, a decrease of $88 million compared to the prior fiscal year. This was primarily due to Site C Project expenditures as major scopes of work were completed in the prior fiscal year, resulting in less construction costs for the current year. The decrease was partially offset by increases in transmission, generation and general capital expenditure categories. Annual capital expenditure investments can vary depending on the timing and scope of projects.

Transmission lines and substation replacements and expansion included capital expenditure investments on transmission overhead lines, cables, substations, telecommunication systems, and transmission power equipment. Key capital expenditure investments included the following projects/programs: Prince George to Terrace Capacitors, North Coast Transmission Line, Treaty Creek Terminal – Transmission Load Interconnection , Goldstream Substation Property Purchase, Peace to Kelly Lake Stations Sustainment, 1L243 – Transmission Load Increase and Campbell Heights Substation Property Purchase.

Generation replacements and expansion included capital expenditure investments on dam safety projects as well as on generating facilities and related major equipment such as turbines, generators, governors, exciters, transformers, and circuit breakers. Key capital expenditure investments included the following projects: John Hart Dam Seismic Upgrade, Ladore Spillway Seismic Upgrade, Strathcona Discharge Upgrade, Ruskin – Left Abutment Slope Sinkhole Remediation, Fort Nelson – Regional Reliability Improvement, W.A.C. Bennett Dam Seal Low Level Outlets, and Mica – Unit 1-Unit 4 Circuit Breaker and Iso-phase Bus Replacement.

Distribution system improvements and expansion included capital expenditure investments on customer driven work, end of life asset replacements, Fleetwood – Distribution Load Interconnection project, and system expansion and improvements.

General included capital expenditure investments on various building development programs, other technology projects, and vehicles.

Site C incurred capital expenditure investments across the project, primarily for work areas such as balance of plant, turbines and generators, diversion tunnel backfill, infrastructure, and project management and support services.

Rate Regulation

BC Hydro is regulated by the BCUC, who is independent from BC Hydro and is authorized to set BC Hydro's rates.

Key Regulatory Applications Impacting Financial Results

In accordance with the Government of B.C.'s Direction No. 9 to the BCUC, the BCUC issued Order No. G76-25, on March 26, 2025, to approve a bill increase of 3.75 per cent for each of the 2025/26 and 2026/27 fiscal years.

Risk Management

BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. This section of the MD&A discusses risks that may impact financial performance prior to the potential application of regulatory accounts where applicable.

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of BCUC-approved regulatory accounts. The use of regulatory accounts is common amongst regulated utility industries throughout North America. Regulatory accounts assist in matching costs and benefits for different generations of customers and to defer for future recovery or refund in rates the differences between planned and actual costs or revenues that arise due to uncontrollable events. BC Hydro's approach to the recovery of its regulatory accounts is included in the Fiscal 2026 – Fiscal 2027 Revenue Requirements Application.

In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives are outlined at bchydro.com/serviceplan.

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue, cost of energy, and finance charges. These are influenced by several elements, which are generally categorized into the following six factors:

- Hydro generation;
- Electricity imports/exports;
- Customer demand;
- Trade income;
- Deliveries from electricity purchase agreements; and
- Interest rates.

In addition to the six factors identified above, changes in United States tariff and trade policies including responses by Canada and British Columbia continue to be monitored to determine potential financial impacts to BC Hydro. Where applicable, the potential impacts have been included in the discussion on BC Hydro's significant financial risks below.

Hydro Generation

The amount of generation available influences BC Hydro's financial results by changing the amount of surplus energy we have available to export or the amount of deficit energy we need to import to meet domestic load. The amount of available generation is driven primarily by the amount and timing of inflows (hydrology) into BC Hydro-dispatched plants and reservoirs and initial reservoir storage conditions prior to seasonal snow melt (freshet). Lower water inflows can significantly reduce hydro generation and can have a material impact on BC Hydro's cost of energy in the current fiscal and future years.

The range of inflows, year to year, can significantly influence available generation: over 16,000 GWh can separate the wettest years from the driest. The amount of available generation, seasonally, is also impacted by the availability of both BC Hydro and Independent Power Producer generating assets and by BC Hydro's operation of system storage.

Water inflows (energy equivalent) to the system for the year ended March 31, 2026 were below the historical average, although higher than the prior fiscal year. The below average inflows for the current fiscal year were primarily driven by the below average snowpack in the spring of 2025. Despite this, as at March 31, 2026, system energy storage was tracking above the ten-year historic average and higher than March 31, 2025 due to net imports and greater total inflows.

Electricity Imports/Exports

Electricity imports/exports are impacted by electricity and gas prices and volumes, which themselves, are variable and a function of gas and electricity market fundamentals and water inflows.

While meeting domestic customer demand, environmental regulations and treaty obligations, BC Hydro attempts to operate the system to take maximum advantage of market energy prices – buying from the markets when prices are low and selling when prices are high. In so doing, BC Hydro seeks to optimize the combined effects of these elements and reduce the net cost of energy for our domestic customers.

For the year ended March 31, 2026, net electricity imports were 4,344 GWh compared to net electricity imports of 8,356 GWh in the prior fiscal year and the average price of the electricity imports were lower than the prior year.

Customer Demand

Customer demand for electricity is generally forecast to increase in the long term as British Columbia’s population and economy continue to grow. Long-term customer load projections are inherently uncertain, especially during the current energy transition and global economic volatility, which has been exacerbated by United States trade policy and geopolitical tensions. In particular, large industrial customers can have significant variability in load as a result of changing supply and demand balances in world commodity markets and related commodity prices. Economic slowdowns driven by higher energy costs, weakening global markets or trade restrictions may lead to reduced energy consumption from our key industrial and commercial customers, potentially lowering revenues. In addition, there can be variability for residential and commercial customers due to changes in the rate of population growth, changes in the types of residential and commercial buildings constructed, changes in end-use technology, general economic conditions, the pace of electrification and the rate of uptake in Demand-Side Management programs.

There can also be short-term fluctuations in customer load due to the timing of new large customer facility start-ups, electrification project implementation and existing customer facility closures and restarts. Temperature can have an impact on residential load and to a lesser extent, commercial and light industrial load, with colder or warmer years resulting in higher demand for electrical heating or air conditioning than in average years.

Excluding electricity exports, domestic load volumes for the year ended March 31, 2026, were 1 per cent higher compared to the prior fiscal year.

Trade Income

Trade Income for regulatory accounting is affected by numerous factors which can differ from year to year. Volumes and prices are variable and are impacted by supply and demand, transmission and transport availability or constraints. In addition, changes in United States tariff and trade policies including responses by Canada and British Columbia could have impacts to Trade Income.

Deliveries from Electricity Purchase Agreements (EPAs)

Energy delivered under EPAs has a different cost than both energy generated by BC Hydro and energy purchased or sold in energy markets. Therefore, as the proportion of energy deliveries from EPAs changes, BC Hydro's cost of energy changes. BC Hydro's portfolio of EPAs includes a significant portion of hydro and wind resources and the amount of generation under these contracts is driven by weather patterns, hydrology, and other operational factors that impact deliveries, which may vary significantly from year to year.

For the year ended March 31, 2026, overall energy delivered from EPAs were consistent with the forecast. While hydro generation delivered less energy than expected, the shortfall was offset by higher than forecast deliveries from other generation sources, primarily biomass, wind and thermal.

Interest Rates

BC Hydro targets to have approximately 15% of its debt as variable debt and manages variable debt within a +/- 10% range. Variable debt is impacted by changes to interest rates which results in variability in interest expense. Variability in interest expense on borrowings is influenced by both the volume of debt BC Hydro requires and the interest rate paid on that debt. BC Hydro accepts this variability in return for the savings obtained from normally lower short-term rates and for cash/debt management purposes, within policy limits and parameters established by its liability risk management annual strategic plan.

As at March 31, 2026, approximately 15 per cent of the Company's existing net debt had a maturity of one year or less and is exposed to changes to interest rates at the time of refinancing.

BC Hydro is also exposed to interest rate risk on future long-term debt issuances. To reduce variability in interest expense on future long-term debt issuances and lock in interest rates related to future long-term debt issuances, as at March 31, 2026, BC Hydro had interest rate hedges in place with an aggregate notional principal of $3.58 billion, hedging a portion of its forecast long-term debt issuances out to and including fiscal 2029/30.

In addition, ongoing changes in United States trade policy, geopolitical issues, economic growth, and inflation could have impacts to interest rates.

Future Outlook

The Budget Transparency and Accountability Act requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2026 forecast net income for 2026/27 at $712 million which is consistent with the amount required by Order in Council No. 485. Net income for the period 2027/28 – 2028/29 is forecast to be $712 million annually.

The Company's financial performance can fluctuate significantly due to the factors discussed in the preceding section, many of which are non-controllable. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts.

As part of Canada's trade disputes with the U.S. starting in 2025, BC Hydro continues to limit procurement from U.S. suppliers where viable in alignment with provincial regulation enacted under the Economic Stabilization Tariff Response Act. BC Hydro purchases the vast majority of goods and services from Canadian suppliers, but continues advancing longer-term plans to diversify its supply chain and reduce reliance on U.S. suppliers, including for certain critical equipment and services that are typically sourced from the U.S. and have no readily available alternatives. Cost impacts from tariffs have remained relatively low. However, tariffs continue to represent risks of cost escalation and contribute to uncertainty in cost projections and planning.

The potential for a global economic downturn or weaker growth due to ongoing geopolitical tensions and the trade disputes remain. These factors carry significant implications for federal and provincial economies, as well as BC Hydro's load, revenue, trade, supply chains, interest rate risk, and ability to deliver capital projects. These economic uncertainties make it difficult to predict the ultimate adverse effects on BC Hydro's performance, financial condition, operational results, and cash flows.

Uncertainty around water inflows (high or low) could have an adverse impact on BC Hydro's future performance. Forecast water inflows for 2026/27 are expected to be above the historical average due to above average snowpack levels for the Columbia and Peace basins, which account for 60% of BC Hydro's annual generation. 2026/27 water supply will also be influenced by precipitation over the remainder of the fiscal year. In any fiscal year, cost of energy may be higher due to imports in times of deficit and domestic revenues may be higher due to exports in times of surplus. Variability in seasonal and annual surplus or deficit amounts affects BC Hydro's cost of energy, domestic revenues, and financial performance.

Capital Expenditures

BC Hydro has the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. The North Coast Transmission Line (NCTL) Project is not yet Board approved for Implementation phase and therefore not included in the Projects over $50 million table below.

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Projects Recently Put into Service				
Natal – 60-138 kV Switchyard Upgrade Project This project addressed reliability, regulatory and safety risks at the Natal substation as the 60-138kV switchyard equipment was at end-of-life and removed PCB containing equipment by the December 31, 2025 Federal PCB Regulation deadline.	2025 In-Service	$78	$7	$85
Site C Project** This project constructed a third dam and a hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It can produce approximately 5,100 gigawatt-hours of electricity annually and has between 1,150 – 1,230 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. **Site C project total anticipated cost and project cost to date include capital costs, charges subject to regulatory deferral and certain operating expenditures.* ***As approved in June 2021, the Site C project budget is $16 billion. In August 2025, the sixth and final generating unit was placed in-service. Trailing costs and wrap-up work remain on the project.*	2025 In-Service	$14,917	$1,083	$16,000*

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Vancouver Island Radio System Project This project replaced the end-of-life BC Hydro telecommunication system on Vancouver Island with a modernized system to improve reliability and increase communication capacity. Upgrades were completed at 38 substations and microwave repeater sites and the project included installation of a new microwave radio link. **The total cost represents the gross cost of the project and has not been netted for a contribution of $1M.*	2025 In-Service	$55	$3	$58*
Various Sites – EV Charging Infrastructure Implementation Program This program was required to deliver BC Hydro's portion of the Provincial Government's mandate B.C. 's Electric Highway and target of 10,000 public EV charging stations by 2030. **The total cost represents the gross cost of the project and has not been netted for the Provincial and Federal Government's funding of $8 million and $10 million, respectively.*	2025 In-Service	$72	$-	$72*
Goldstream Substation Property Purchase* This project was to acquire a property near the Goldstream area of Langford to build a new outdoor substation to support load growth. **Purchase was previously named "Goldstream – Property Purchase"*	2025 In-Service	$54	$7	$61

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Ongoing				
Mica Replace Units 1 to 4 Generator Transformers Project This project addressed the reliability and safety risks of the Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station, which were nearing end of life and went in-service in 2022. One of the transformers developed issues and was exchanged with a spare transformer. The Board approved the purchase and construction of infrastructure to store an additional spare transformer.	2025 In-Service	$86	$-	$86
2L143 – Cable Replacement Project This is an emergency project to address reliability, environmental, and seismic risks associated with the existing transmission cable 2L143 between Horsey Substation and Esquimalt Substation and to address load growth.	2026 Targeted In-Service	$40	$60	$100
2L333 – Load Interconnection – Enbridge APP CS16 Project This project is to connect the Enbridge Westcoast CS16 facility to BC Hydro's transmission grid. **The total cost represents the gross cost of the project and has not been netted for estimated Federal government contributions of $15M nor a customer's contribution of $46M.*	2026 Targeted In-Service	$21	$111	$132*

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior) Project This project is required to recoat the interior and exterior of the Units 1 & 2 penstocks at Cheakamus generating station, as well as the shared steel lined tunnel section, due to corrosion and loss of steel.	2026 Targeted In-Service	$47	$6	$53
Fort Nelson – Regional Reliability Improvement Project This project is required to address reliability risks to the Fort Nelson region's power supply by installing a new dual fuel generator at the Fort Nelson Gas Generating station.	2026 Targeted In-Service	$51	$23	$74
Mainwaring Station Upgrade Project This project is required to maintain the reliability of the Mainwaring substation, and address safety and environmental risks at the substation and load growth.	2026 Targeted In-Service	$102	$52	$154
Mica Townsite Apartment Accommodation Project This project is required to construct permanent accommodations for the long-term workforce at the Mica Generating station which is requiring significant investment over time to sustain the health of its assets.	2026 Targeted In-Service	$50	$17	$67
Ruskin – Left Abutment Slope Sinkhole Remediation Project This project will address the left abutment slope instability and remediate the sinkhole issues adjacent to the Ruskin Generating Station to mitigate dam safety risks.	2026 Targeted In-Service	$90	$39	$129

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
1L037 Jervis and Agamemnon Crossings Project This project is to address safety and reliability risks associated with circuit 1L037's marine crossings over Jervis Inlet and the Agamemnon Channel.	2027 Targeted In-Service	$27	$37	$64
1L243 Transmission Load Increase (HVC) Project This project is required to upgrade transmission infrastructure to accommodate Teck Resources Ltd.'s request to provide power for Teck's Highland Valley Copper (HVC) Mine Life Extension project. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $3M.*	2027 Targeted In-Service	$57	$85	$142*
Comox – Puntledge Flow Control Improvements Project This project is required to address public safety risk relating to water conveyance at Comox-Puntledge; the Puntledge Diversion Reach is a heavily used public recreation area.	2027 Targeted In-Service	$52	$1	$53
EV Charging Ports DCFC Program* This program is required to deliver BC Hydro's portion of the Provincial Government's mandate for the installation of public EV charging ports by 2030. **Previously named "Public EV Charging – Light-Duty Program"* ***The total cost represents the gross cost and has not been netted for the Provincial and*	2027 Targeted In-Service	$61	$65	$126**

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Federal Government's contributions which are dependent on the final actual project costs and what costs are eligible under the agreement.				
Fleetwood – Distribution Load Interconnection (SLS Servicing) Project This project is on behalf of BC Hydro's customer, the Province of BC, to supply the Surrey-Langley-Skytrain extension and will also allow BC Hydro to reinforce the flexibility and reliability of the overall distribution system. **The total cost represents the gross cost of the project and has not been netted for a Provincial government contribution of $81M.*	2027 Targeted In-Service	$50	$108	$158*
Kimberley to Marysville – Substation Relocation Project This project is to address the reliability, safety and environmental risks associated with three bulk oil circuit breakers and other station assets at Kimberley substation which have reached their end-of-life.	2027 Targeted In-Service	$10	$63	$73
Long Lake Terminal Station – Transmission Load Interconnection Project This project is to facilitate the interconnection of customers' facilities to BC Hydro's Long Lake terminal substation. Under BC Hydro's standard tariffs and policies, customers are required to pay a portion of this project's costs. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $1M.*	2027 Targeted In-Service	$39	$41	$80*

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Materials Classification Facility Project This project is to complete the construction and commissioning of the new Materials Classification Facility on the BC Hydro Surrey Campus. The facility will receive, classify and process hazardous polychlorinated biphenyl (PCB) and non-hazardous waste from BC Hydro operations across the province, and process materials for safe off-site recycling or disposal.	2027 Targeted In-Service	$39	$37	$76
Minette – Transmission Load Interconnection Project This project is to facilitate the interconnection of a customer's facility to BC Hydro's Minette Substation. Under BC Hydro's standards tariffs and policies, the customer is required to pay a portion of this project's costs. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $20M.*	2027 Targeted In-Service	$30	$42	$72*
Sperling Substation Metalclad Switchgear Replacement Project This project will address the existing asset health, reliability and safety risks associated with the 12kV 60 series feeder section and the bulk oil breaker in the 12 kV 70/80 series feeder section, insufficient electrical clearances in the 60 series feeder section, and arc flash safety risks associated with the 12kV indoor metalclad switchgear.	2027 Targeted In-Service	$70	$13	$83

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Transmission Customer Load Interconnection Project This project is to facilitate the interconnection of customers' facilities to BC Hydro's Transmission system. Under BC Hydro's standards tariffs and policies, the customer is required to pay a portion of this project's costs. ** The total cost represents the gross cost of the project and has not been netted for estimated Federal government contributions of $9M nor a customer’s contribution of $5M.*	2027 Targeted In-Service	$14	$38	$52*
Tsay Keh Dene – Diesel Station Capacity Increase Project This project is required to increase the Tsay Keh Dene diesel generation station’s firm capacity to meet load growth.	2027 Targeted In-Service	$19	$32	$51
Campbell River II Field Facility Redevelopment Project This project is required to construct a new field operations building to meet BC Hydro’s functional, safety, operational and long-term business requirements for the Campbell River region.	2028 Targeted In-Service	$9	$63	$72
Clayburn – Substation Upgrade (2nd Phase) Project This project is to address reliability risk by adding a new 230/25kV, 150 MVA power transformer and two new feeder sections to increase the firm capacity at Clayburn substation.	2028 Targeted In-Service	$9	$48	$57

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Ladore Spillway Seismic Upgrade Project This project is to replace the existing spillway gates system to address known seismic and reliability deficiencies at the Ladore dam.	2028 Targeted In-Service	$144	$228	$372
Mica – U1 – U4 Circuit Breaker and Iso-phase Bus Replacement Project This project will address reliability risks at the Mica Creek Generating Station by replacing the aging and obsolete unit 1 to 4 generator circuit breakers, isolated phase buses and other ancillary equipment.	2028 Targeted In-Service	$51	$125	$176
Northwest – Substations Outage Mitigation Project This project is required to improve supply availability to a customer by mitigating planned line outages in the radial bulk transmission system that supplies the Northwest. Under BC Hydro's standard tariffs and policies, the customer is required to pay a portion of this project's costs. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $2M.*	2028 Targeted In-Service	$28	$61	$89*
Peace to Kelly Lake Stations Sustainment Project This project is required to maintain the reliability of BC Hydro's bulk transmission system by replacing station assets within the Peace to Kelly Lake transmission system that are at end-of-life.	2028 Targeted In-Service	$160	$184	$344

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Prince George to Terrace Capacitors Project This project is required to increase the transfer capacity of the North Coast bulk transmission system to meet growing customer service requests in the region. **The total cost represents the gross cost of the project and has not been netted for estimated Federal government contributions of $97M nor a customer's contribution of $4M.*	2028 Targeted In-Service	$305	$277	$582*
Terzaghi – Spillway Chute Access Improvement Project This project is to address safety and operational risks at the Terzaghi dam due to rockfall hazards that impact access to the spillway chute, diesel generator, and nearby assets.	2028 Targeted In-Service	$9	$53	$62
Treaty Creek Terminal – Transmission Load Interconnection (KSM) Project This project is to facilitate the interconnection for construction power for the planned Kerr-Sulphurets-Mitchell (KSM) Mine to BC Hydro's transmission system. Under BC Hydro's standard tariffs and policies, the customer is required to pay a portion of this project's costs. A future project is planned to supply power for the full mine. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $87M.*	2028 Targeted In-Service	$105	$63	$168*

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Burrard Switchyard – Control Building Upgrade Project This project will address the need of constructing a new control building, establish the communication system, and install the new protection and control equipment for the Burrard switchyard.	2029 Targeted In-Service	$6	$51	$57
Kootenay Canal Modernize Controls Project This project will address reliability, maintainability, and safety of the Kootenay Canal facility by replacing the aged control equipment, exciters, and select governor mechanical components for the four Kootenay Canal generating units.	2029 Targeted In-Service	$33	$28	$61
McLellan – Substation Upgrade Project This project will address system reliability and future load growth at the McLellan substation by adding a new 230/25kV, 150 MVA transformer and 16 new feeder positions.	2029 Targeted In-Service	$14	$63	$77
Mount Pleasant Substation – Transformer and Feeder Sections Addition Project This project will add feeder positions at the Mount Pleasant substation which are needed to supply the forecasted load growth in the South False Creek and Mount Pleasant area.	2029 Targeted In-Service	$9	$81	$90

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Victoria Secondary Network Replacement Project This project will address safety risks associated with the underground Victoria Integrated Secondary Network distribution system by replacing end-of-life equipment in the network vaults.	2029 Targeted In-Service	$5	$110	$115
Bridge River 1 – Recoat Penstocks 1-4 Project This project will address safety and reliability risks of the Bridge River 1 (BR1) penstocks 1-4 by stripping and recoating the failed coatings on the interior and exterior penstock surfaces to extend their service life.	2030 Targeted In-Service	$14	$112	$126
John Hart Dam Seismic Upgrade Project This project will address dam safety risks at the John Hart dam and will significantly improve the overall seismic withstand of the dam structure, the reliability of the spillway gates system, and address inflow imbalance issues between the Ladore dam and John Hart dam.	2030 Targeted In-Service	$469	$443	$912
Strathcona Discharge Upgrade Project This project will address seismic and reliability risks at the Strathcona dam by installing a new low-level outlet structure to provide the capability for a deep reservoir drawdown and converting the three existing spillway gates with a new concrete overflow spillway.	2030 Targeted In-Service	$114	$452	$566

Major Capital Projects (over $50 million)	Targeted Completion Year (Calendar)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Newell Substation Upgrade Project This project will address system reliability and safety risks, and future load growth by replacing the end-of-life feeder section, one power transformer and associated equipment at the Newell substation.	2031 Targeted In-Service	$18	$177	$195
Bridge River 1 Replace Units 1-4 Generators / Governors Project This project will address the deteriorating condition of the aging generators, governors, excitors, and control systems at the Bridge River 1 generating station. The project will improve reliability, restore licensed flow and generation capacity, and increase operating flexibility of the generating station.	2032 Targeted In-Service	$31	$282	$313

Significant IT Projects

Significant IT Project (over $20 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2026 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Ongoing				
Distribution Design Modernization Project This project is required to replace obsolete technology systems used to support BC Hydro's distribution design process with modern, commercially available solutions. Distribution design is a critical function that enables BC Hydro to plan, design, and manage projects to expand, maintain, and upgrade its distribution system.	2027 Targeted In-Service	$19	$35	$54

Appendix A: Progress on Mandate Letter Priorities

The following is a summary of progress made on priorities as stated in the 2025 Mandate Letter from the Minister Responsible.

2025 Mandate Letter Priority	Status as of March 31, 2026
Support the province's economic, climate and reconciliation objectives through the procurement of clean energy, delivery of the BC Hydro Capital Plan and partnerships with First Nations.	**Ongoing** • Progress on this priority is captured throughout this Annual Service Plan Report. For progress on procurement of clean energy, please see Objectives 2.1 and 2.2, for delivery of the BC Hydro capital plan please see Objective 2.1, and for partnerships with First Nations, please see Objectives 4.1 and 4.2.
Keep electricity affordable by ensuring that rates do not increase above inflation, on a cumulative basis between 2017 and 2031, and ensure rates are reasonably predictable and reasonably consistent from year to year.	**Ongoing** • Government's rate stability direction sets BC Hydro's annual average rate increase at 3.75 per cent for 2025/26 and 2026/27. Progress is captured in Objective 3.1. • In Hydro Quebec's 2025 Rate Comparison Report, BC Hydro's 2026 rates are among the lowest in North America. BC Hydro's residential rates are the third-lowest surveyed while those paid by businesses range from the second to fourth- lowest.
Ensure BC Hydro's plans and programs remain relevant, efficient and financially sustainable, while maintaining affordability.	**Ongoing** • Progress on this priority is captured throughout this Annual Service Plan Report. For progress on financial sustainability, please see Objective 3.1. For progress on efforts to maintain affordability please see Objectives 1.1, 2.1, 2.2, and 3.1. For progress on programs remaining relevant and efficient please see Objectives 1.1, 1.2, 2.1, 2.2, 2.3, and 3.1.

<table>
<tr><th>2025 Mandate Letter Priority</th><th>Status as of March 31, 2026</th></tr>
<tr><td>Aligned with the recently announced Clean Power Action Plan, work with First Nations and the renewable power industry through frequent competitive calls for power to secure additional sources of energy and capacity to support a growing clean economy.</td><td>Complete
In April 2024, BC Hydro launched the 2024 Call for Power and awarded 30-year electricity purchase agreements to 10 renewable energy projects in December 2024. The BCUC accepted the Electricity Purchase Agreements for the 10 projects in the 2024 Call for Power in August 2025. The projects will produce electricity at lower cost than BC Hydro’s last call for renewable power in 2010. Details are captured in Objectives 2.2 and 4.2.
Ongoing
BC Hydro launched the 2025 Call for Power in July 2025, which received a strong response from proponents. Electricity purchase agreements will be awarded in Fiscal 2027. Progress is captured in Objectives 2.2 and 4.2.</td></tr>
</table>

2025 Mandate Letter Priority	Status as of March 31, 2026
Continue to identify and advance First Nations ownership opportunities in future calls for power and major transmission investments to advance reconciliation and support economic self-determination.	**Complete** • Each of the 10 projects in the 2024 Call for Power has First Nations asset ownership between 49 per cent and 51 per cent. Details are captured in Objective 4.2. **Ongoing** • The 2025 Call for Power launched in July 2025 with a minimum 25 per cent First Nations equity ownership requirement, while also enabling greater First Nations participation through options for higher ownership levels and additional First Nations benefits beyond equity. Progress is captured in Objective 4.2. • Signed term sheets or deal sheet agreements for the North Coast Transmission Line Phase 1 and 2 with 12 of 14 Nations and all eight Hereditary Chiefs of the Wet'suwet'en Nation, laying the foundation for comprehensive legal partnerships. Progress is captured in Objective 4.2. • BC Hydro is continuing engagement with nine potentially affected First Nations for Phase 3 of the North Coast Transmission Line. Progress is captured in Objective 4.2.

2025 Mandate Letter Priority	Status as of March 31, 2026
Continue to implement BC Hydro's Electrification Plan to attract new innovative industries to BC and advance the switch from fossil fuels to clean electricity in homes and buildings, vehicles and fleets, businesses and industry.	**Ongoing** • BC Hydro has invested over $136 million to advance its Electrification Plan and promote fuel switching in homes and buildings, transportation, and industries. • As of March 31, 2026, these investments have resulted in an emissions reduction of 579 kilotonnes of CO_2e per year, 2,760 gigawatt hours per year in additional energy consumption, and 393 megawatts in demand growth across the buildings, transportation, and industry sectors. • Under the Load Attraction program, 12 customer projects have been approved for funding supporting various sectors of the economy from low-carbon fuels to mining, and in particular critical minerals production.

<table>
<tr><th>2025 Mandate Letter Priority</th><th>Status as of March 31, 2026</th></tr>
<tr><td>Continue to make improvements to accelerate the process for new residential and commercial customer connections under the new Distribution Extension Policy to support the Province’s housing priorities.</td><td>Complete
BC Hydro modernized the Distribution Extension Policy for the first time in 15 years to reduce connection costs for new customers. Since the new extension policy took effect on July 5, 2025, customer payments have decreased approximately 10 per cent on average in proportion to total project value. Details are captured in Objective 1.1.
Ongoing
BC Hydro will evaluate the updated Distribution Extension Policy after an initial three-year implementation period to assess its effectiveness. As extension projects often span multiple years from initiation to completion, this timeframe is required to ensure sufficient data is available to evaluate outcomes.
In 2025/26, BC Hydro continued to streamline work processes by reducing steps for every part of the customer’s project life cycle, from the first customer request through to design, estimating, permitting and construction.</td></tr>
</table>

2025 Mandate Letter Priority	Status as of March 31, 2026
Work with ECS to enhance responsiveness to changing market conditions and demand for large load capacity from potential local and international investors to grow our economy and reduce our emissions while protecting ratepayers.	**Complete** • BC Hydro improved the interconnection pre-queue process ensuring industrial applications were complete and high quality before entering the interconnection queue. This has enabled more efficient processing, clearer information for customers, and reduced rework. Details captured in Objective 1.1. **Ongoing** • Worked with ECS to launch the 2026 Call for Demand for Emerging Industries to provide electricity to the AI and data centre sectors, manage rising electricity demand from these fast-growing industries and maintain affordability for ratepayers. More information is available in Objective 1.1.

2025 Mandate Letter Priority	Status as of March 31, 2026
Conduct ongoing risk assessment and work with the Ministry of Energy and Climate Solutions (ECS) to prepare contingency plans in the event of tariffs imposed by the United States on electricity exports.	**Ongoing** • Powerex Corp., BC Hydro's trading subsidiary, continues to monitor the evolving Canada-U.S. trade landscape and assess the risks and challenges associated with cross border trade issues with respect to electricity. It is coordinating with the Ministry of Jobs and Economic Growth and Ministry of Energy and Climate Solutions in advance of the Canada-U.S.-Mexico Agreement review. At present, the zero-tariff framework for electricity continues to apply and recent decisions at the U.S. Supreme Court have impacted the ability of the executive branch of the current U.S. administration to unilaterally impose tariffs. This is a continuing matter and is being closely followed and monitored.
Pursue opportunities to enhance electrical connections with neighbouring provinces and territories to diversify markets and enhance grid reliability.	**Ongoing** • B.C.-AB Intertie: In 2025/26, BC Hydro provided high-level scope requirements for work needed on the B.C. electrical system in response to the leading alternative in the Alberta Electric System Operator's proposal to restore the intertie's west to east transfer capability. • B.C.-Yukon Intertie: In 2025/26, BC Hydro supported feasibility and preliminary planning work on a Yukon-B.C. intertie. BC Hydro also advanced work on the North Coast Transmission Line, which would need all phases complete to ensure sufficient capacity in northwest B.C. to connect to Yukon's grid.

2025 Mandate Letter Priority	Status as of March 31, 2026
Continue to make improvements to accelerate and expand efforts to support the Province's goal of providing all BC communities with access to high-speed internet connectivity by 2027, while maintaining cost effectiveness and reliability for BC Hydro ratepayers, and safety for workers.	**Ongoing** • BC Hydro continues to work with the Ministry of Citizen Services to proactively identify and perform necessary "make ready" work where telecom infrastructure is expected to be installed on BC Hydro distribution poles, resulting in shorter timelines for projects in those areas once awarded by the province to the telecom carrier. • BC Hydro continues to lead the Broadband Connectivity Working Group with telecommunications companies, and the Ministries of Energy and Climate Solutions, Citizens' Services, and Water, Land, and Resource Stewardship to improve transparency, communication, and process. • BC Hydro is actively working with telecommunications companies to coordinate early in project planning to identify any risks and required preparatory work upfront, helping to reduce delays and improve project timelines.
Develop and implement a strategic plan to improve access to clean, reliable and affordable energy in the Non-Integrated Areas, in alignment with the provincial Remote Community Energy Strategy.	**Ongoing** • Conducted the third and final phase of engagement with non-integrated area (NIA) Nations on the NIA Strategy. The draft Strategy was shared with NIA Nations for comment. The NIA Strategy document is expected to be published in June 2026. Progress is captured in Objective 4.1.

Work with ECS to co-develop targeted programs to support clean energy and efficiency upgrades for low-income households and multi-unit residential buildings.	**Complete** • In September 2024, BC Hydro launched a new integrated energy efficiency program specifically for multi-unit residential buildings (MURBs) to address their unique needs. The programs focus is on whole-building retrofits including heat pumps, heat pump water heaters, lighting, windows and electrical capacity upgrades. • BC Hydro, in partnership with the Province, launched an integrated Social Housing Energy Savings Program in 2025/26 to identify and implement energy savings and fuel switching retrofits for multi-unit residential social housing buildings. • BC Hydro launched the Condo and Apartment Rebate Program, an in-suite heat pump rebate offer in July 2025. The program provides rebates for individual condo owners and rental building owners to upgrade space and water heating equipment in their unit. • BC Hydro worked with the Province to launch their income-qualified CleanBC Condo and Apartment Rebates on July 15, 2025. • In June 2025, BC Hydro, in partnership with the Province and FortisBC, launched the Partners In Indigenous Energy Efficiency & Resilience program that offers support to Indigenous Governing Bodies that are coordinating energy upgrades in homes for their community members. • BC Hydro expanded its Energy Conservation Assistance Program in July 2025 to focus on free heat pumps, insulation and other weatherization measures.

2025 Mandate Letter Priority	Status as of March 31, 2026
	Ongoing • BC Hydro also continues to support low-income customers through: • Flexible payment options including equal payment plans, one-time payment deferrals, and interest-free repayment of overdue balances; • Not disconnecting residential customers for non-payment during periods of extreme cold temperatures. • In 2025/26, BC Hydro provided Customer Crisis Fund support to 6648 customers. • In 2025/26, over 1200 income qualified households participated in the Energy Conservation Assistance Program and over 8800 households received an energy saving kit. • BC Hydro continued to deliver the free Air Conditioner Program in 2026/26 for the most vulnerable customers, who receive a recommendation letter from their regional health authority. • BC Hydro’s Energy Efficiency Plan for Fiscal 2025 to Fiscal 2027 includes over $700 million in tools, technology, programs, and rebates for customers to encourage more energy efficient choices to support the energy transition. This includes $80 million dedicated to support income-qualified households, social housing and Indigenous communities.

2025 Mandate Letter Priority	Status as of March 31, 2026
Support the Province's target of 10,000 public EV charging stations by 2030 by leading station deployment, working with other parties and providing clean, reliable electricity to power vehicles and stations.	**Complete** • In 2025/26, the BC Hydro EV public charging network added 45 new sites, that accounted for 275 new charging ports, including transitioning the operations of 26 sites from the Ministry of Transportation and Transit to BC Hydro. With the transition, BC Hydro now operates 85 per cent of the sites that make up B.C.'s Electric Highway. **Ongoing** • As of March 2026, BC Hydro had 891 charging ports at 188 sites across B.C., with 694 fast charging ports. BC Hydro's charging network is expected to reach over 1,000 charging ports by Q4 of 2026/27.

Appendix B: Subsidiaries and Operating Segments

Active Subsidiaries

Powerex Corp

Operating out of Vancouver BC, Canada, Powerex Corp. is a wholesale energy marketer, whose activities include trading electricity, environmental products, natural gas, and related financial and physical energy products and services in North America.

Powerex Corp. ("Powerex" or "the Company") was incorporated in Canada on December 13, 1988 under the BC Corporations Act (formerly the Company Act of BC) and commenced operations on April 1, 1989. Powerex is a wholly-owned corporate subsidiary of BC Hydro, a Crown corporation of the Province of British Columbia.

Through its contractual agreements with BC Hydro, Powerex supports BC Hydro's system requirements by importing and exporting energy. Powerex also markets, through a contractual agreement with the Province, the Canadian Entitlement to the Downstream Power Benefits under the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex. The Chair of the Powerex Board ensures the Board of BC Hydro is informed of Powerex's key strategies and business activities. The Powerex CEO also informs the BC Hydro President & CEO and Executive Team of Powerex's key strategies and business activities.

Powerex operates in competitive and complex wholesale energy-markets, which can cause net income in any given year to vary significantly. Market, economic and weather conditions, reduced hydro system flexibility, unrealized mark-to-market gains or losses and the strength of the Canadian dollar can materially impact Powerex trade income. Over the previous five years (2021/22 to 2025/26), Powerex trade income has ranged from $379 million to $1,052 million. For more information, visit powerex.com.

Board of Directors:

- Catherine Roome – Chair
- Sam Drier
- William Duvall
- Don Kayne
- Marilyn Loewen Mauritz
- Bob McDonald
- Charlotte Mitha

Powertech Labs Inc

Powertech Labs Inc., based in Surrey, British Columbia since its inception 1988 is a wholly owned subsidiary of BC Hydro. Operating as a commercial entity, Powertech supports innovation through three main businesses lines: testing services, engineering services and hydrogen infrastructure. Powertech provides innovative solutions, specialized testing, and technical expertise to global industry partners, contributing to a safe and sustainable energy future. Internationally recognized for its technical leadership in various fields related to electric utilities and sustainable energy industries, Powertech Labs is also a leader in hydrogen technology. It has extensive experience designing and producing innovative hydrogen vehicle refueling and transportation systems, playing a key role in BC Hydro's commitment to supporting the Province's B.C. Hydrogen Strategy. Powertech has supplied the majority of hydrogen station technology in B.C. and is a leading provider across Canada.

The President and CEO of Powertech reports to Powertech's Board of Directors through its Chair. The Powertech Board is chaired by BC Hydro's Vice President, Project Delivery, and its Directors include senior Executives and Directors of BC Hydro.

Powertech Labs has an active subsidiary, Powertech USA, Inc., which is a wholly owned, unregulated commercial subsidiary that began operations on September 1, 2023. Located in Boston, Massachusetts, Powertech USA focuses on developing hydrogen transport and fueling infrastructure solutions.

Over the last five years (2021/22 to 2025/26), Powertech's net income has ranged from a net loss of $2 million to net income of $10 million. For more information, visit powertechlabs.com.

Board of Directors:

- Melissa Holland - Chair
- Henry Honda
- Karen Tam Wu
- Tony Penikett
- Bruce Ralston

Other Subsidiaries

BC Hydro has created or retained a number of other subsidiaries for various purposes, including holding licences in other jurisdictions, to manage real estate holdings, and to manage various risks. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd.

Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd.

Administers and supplies the labour force to specified projects.

Tongass Power and Light Company

Provides electrical power to Hyder, Alaska from Stewart, B.C. due to its remoteness from the Alaska electrical system.

Nominee Holding Companies and/or Inactive Subsidiaries/Dormant Subsidiaries

BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of March 31, 2026, these other subsidiaries consisted of the following:

- British Columbia Hydro International Limited
- British Columbia Power Exchange Corporation
- British Columbia Power Export Corporation
- British Columbia Transmission Corporation
- Columbia Estate Company Limited*
- Edmonds Centre Developments Limited*
- Fauquier Water and Sewerage Corporation
- Hydro Monitoring (Alberta) Inc.*
- Victoria Gas Company Limited
- Waneta Holdings (US) Inc.*
- 1111472 BC Ltd

Appendix C: Auditor's Report and Audited Financial Statements

CONSOLIDATED
FINANCIAL STATEMENTS
2025/26

Management Report

The consolidated financial statements of British Columbia Hydro and Power Authority (BC Hydro) are the responsibility of management and have been prepared in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily involves the use of estimates which have been made using careful judgment. In management's opinion, the consolidated financial statements have been properly prepared within the framework of the accounting policies summarized in the consolidated financial statements and incorporate, within reasonable limits of materiality, all information available at June 4, 2026. The consolidated financial statements have also been reviewed by the Audit and Finance Committee and approved by the Board of Directors. Financial information presented elsewhere in this Annual Service Plan Report is consistent with that in the consolidated financial statements.

Management maintains systems of internal controls designed to provide reasonable assurance that assets are safeguarded and that reliable financial information is available on a timely basis. These systems include formal written policies and procedures, careful selection and training of qualified personnel, appropriate delegation of authority, and segregation of responsibilities within the organization. An internal audit function independently evaluates the effectiveness of internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee.

The consolidated financial statements have been audited by an independent external auditor. The external auditors' responsibility is to express their opinion on whether the consolidated financial statements, in all material respects, fairly present BC Hydro's financial position, financial performance and cash flows in accordance with IFRS Accounting Standards. The Independent Auditor's Report, which follows, outlines the scope of their audit and their opinion.

The Board of Directors, through the Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit and Finance Committee, comprised of directors who are not employees, meets regularly with the external auditors, the internal auditors and management to satisfy itself that each group has properly discharged its responsibility with respect to internal controls and financial reporting. The Audit and Finance Committee reviews the consolidated financial statements and management's discussion and analysis and recommends their approval to the Board of Directors. The internal and external auditors have full and open access to the Audit and Finance Committee, with and without the presence of management.

Charlotte Mitha
President and Chief Executive Officer

Ryan Layton
Executive Vice President, Finance, Supply Chain, Regulatory and Chief Financial Officer

Vancouver, Canada
June 4, 2026

KPMG LLP
PO Box 10426 777 Dunsmuir Street
Vancouver BC V7Y 1K3
Canada
Telephone (604) 691-3000
Fax (604) 691-3031

INDEPENDENT AUDITOR'S REPORT

To the Minister of Energy and Climate Solutions, Province of British Columbia and the Board of Directors of British Columbia Hydro and Power Authority

Opinion

We have audited the consolidated financial statements of British Columbia Hydro and Power Authority (the Entity), which comprise:

- the consolidated statements of financial position as at March 31, 2026
- the consolidated statements of comprehensive income for the year then ended
- the consolidated statements of changes in equity for the year then ended
- the consolidated statements of cash flows for the year 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 March 31, 2026, and its consolidated financial performance and its consolidated cash flows for the year 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.

Other Information

Management is responsible for the other information. Other information comprises the information, other than the financial statements and the auditor's report thereon, included in Management's Discussion and Analysis.

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, other than the financial statements and the auditor's report thereon, included in the Management's Discussion & Analysis as at the date of this auditor's report.

If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

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

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards, 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.

- 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.
- 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.

KPMG LLP

Chartered Professional Accountants

Vancouver, Canada
June 4, 2026

Audited Financial Statements

Consolidated Statements of Comprehensive Income

for the years ended March 31 (in millions)	**2026**	2025
Revenues (Note 4)		
Domestic	**$ 6,350**	$ 6,049
Trade	**1,244**	1,429
	7,594	7,478
Expenses		
Operating expenses (Note 5)	**6,690**	6,399
Finance charges (Note 6)	**864**	1,094
Net Income (Loss) Before Movement in Regulatory Balances	**40**	(15)
Net movement in regulatory balances (Note 16)	**681**	602
Net Income	**721**	**587**
OTHER COMPREHENSIVE INCOME		
Items That Will Be Reclassified to Net Income		
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 24)	**21**	54
Reclassification to income of derivatives designated as cash flow hedges (Note 24)	**3**	(88)
Foreign currency translation gains (losses)	**(21)**	36
Items That Will Not Be Reclassified to Net Income		
Actuarial gain (loss)	**442**	(94)
Other Comprehensive Income (Loss) before movement in regulatory balances	**445**	**(92)**
Net movements in regulatory balances (Note 16)	**(427)**	66
Other Comprehensive Income (Loss)	**18**	(26)
Total Comprehensive Income	**$ 739**	$ 561

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Financial Position

(in millions)		**As at March 31, 2026**		As at March 31, 2025
ASSETS				
Current Assets				
Cash and cash equivalents (Note 8)	**$**	**122**	$	136
Restricted cash (Note 8)		**54**		35
Accounts receivable and accrued revenue (Note 9)		**998**		820
Inventories (Note 10)		**444**		452
Prepaid expenses		**187**		230
Sinking funds (Note 15)		**-**		225
Derivative financial instrument assets (Note 24)		**234**		260
		2,039		2,158
Non-Current Assets				
Property, plant and equipment (Note 11)		**45,507**		42,945
Right-of-use assets (Note 12)		**1,132**		1,180
Intangible assets (Note 13)		**666**		651
Derivative financial instrument assets (Note 24)		**196**		106
Sinking funds (Note 15)		**56**		54
Other assets (Note 14)		**229**		154
		47,786		45,090
Total Assets		**49,825**		47,248
Regulatory Balances (Note 16)		**4,841**		5,930
Total Assets and Regulatory Balances	**$**	**54,666**	$	53,178
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities (Note 17)	**$**	**2,296**	$	2,027
Short-term borrowings and current portfolio of long-term debt (Note 18)		**5,347**		5,284
Unearned revenues and contributions in aid (Note 21)		**134**		123
Derivative financial instrument liabilities (Note 24)		**119**		158
		7,896		7,592
Non-Current Liabilities				
Long-term debt (Note 18)		**29,235**		27,180
Lease liabilities (Note 20)		**1,212**		1,270
Derivative financial instrument liabilities (Note 24)		**26**		118
Unearned revenues and contributions in aid (Note 21)		**3,242**		3,069
Post-employment benefits (Note 23)		**517**		862
Other liabilities (Note 25)		**1,481**		1,423
		35,713		33,922
Total Liabilities		**43,609**		41,514
Regulatory Balances (Note 16)		**2,067**		3,410
Total Liabilities and Regulatory Balances		**45,676**		44,924
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**8,979**		8,261
Accumulated other comprehensive loss		**(49)**		(67)
		8,990		8,254
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$**	**54,666**	$	53,178

Commitments and Contingencies (Notes 11 and 26)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

Glen Clark
Board Chair and Audit and Finance Committee Chair

Consolidated Statements of Changes in Equity

(in millions)	Cumulative Translation Reserve	Unrealized Loss on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2024	$ 10	$ (51)	$ (41)	$ 60	$ 7,677	$ 7,696
Distribution to the Province	-	-	-	-	(3)	(3)
Comprehensive Income	8	(34)	(26)	-	587	561
Balance as at March 31, 2025	18	(85)	(67)	60	8,261	8,254
Distribution to the Province	-	-	-	-	(3)	(3)
Comprehensive Income	(6)	24	18	-	721	739
Balance as at March 31, 2026	$ 12	$ (61)	$ (49)	$ 60	$ 8,979	$ 8,990

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

for the years ended March 31 (in millions)	**2026**	2025
Operating Activities		
Net income	**$ 721**	$ 587
Regulatory account transfers (Note 16)	**(681)**	(602)
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 7)	**1,354**	1,200
Unrealized gains on derivative financial instruments	**(352)**	(240)
Post-employment benefits expense	**76**	59
Interest accrual	**1,219**	1,168
Other items	**(16)**	(23)
	2,321	2,149
Changes in working capital and other assets and liabilities (Note 19)	**228**	(173)
Interest paid	**(1,219)**	(1,165)
Income taxes paid	**(1)**	(5)
Cash provided by operating activities	**1,329**	806
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(3,763)**	(3,514)
Cash used in investing activities	**(3,763)**	(3,514)
Financing Activities		
Long-term debt issued (Note 18)	**2,923**	4,217
Long-term debt retired (Note 18)	**(2,023)**	(10)
Receipt of revolving borrowings	**9,980**	8,414
Repayment of revolving borrowings	**(8,713)**	(9,919)
Payment of principal portion of lease liability	**(90)**	(75)
Settlement of hedging derivatives	**154**	142
Other items	**196**	(27)
Cash provided by financing activities	**2,427**	2,742
Increase (Decrease) in cash and cash equivalents	**(7)**	34
Effect of currency translation on cash balances	**(7)**	6
Cash and cash equivalents, beginning of year	**136**	96
Cash and cash equivalents, end of year	**$ 122**	$ 136

See Note 19 for Supplemental disclosure of cash flow information

See accompanying Notes to the Consolidated Financial Statements.

Note 1: Reporting Entity

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown Corporation of the Government of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia. The head office of the Company is 333 Dunsmuir Street, Vancouver, British Columbia.

The consolidated financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly owned operating subsidiaries Powerex Corp. (Powerex), and Powertech Labs Inc. (Powertech), (collectively with BC Hydro, the Company). All intercompany transactions and balances are eliminated on consolidation.

Note 2: Basis of Presentation

(a) Basis of Accounting

These consolidated financial statements have been prepared in accordance with IFRS Accounting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). The material accounting policies are set out in Note 3.

These consolidated financial statements were approved by the Board of Directors on June 4, 2026.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for natural gas inventories in Note 3(j), financial instruments that are accounted for at fair value through profit and loss according to the financial instrument categories as defined in Note 3(k) and the post-employment benefits obligation as described in Note 3(p).

(c) Functional and Presentation Currency

The functional currency of BC Hydro and all of its subsidiaries, except for Powerex, is the Canadian dollar. Powerex's functional currency is the United States (U.S.) dollar. These consolidated financial statements are presented in Canadian dollars and financial information has been rounded to the nearest million.

(d) Key Assumptions and Significant Judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions in respect of the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those judgments, estimates, and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about significant areas of judgment, estimates and assumptions in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is as follows:

(i) Retirement Benefit Obligation

BC Hydro operates a defined benefit statutory pension plan for its employees, which is accounted for in accordance with IAS 19, *Employee Benefits*. Actuarial valuations are based on key assumptions which include employee turnover, mortality rates, discount rates, earnings increase and expected rate of return on retirement plan assets. Judgment is exercised in determining these assumptions. The assumptions adopted are based on prior experience, market conditions and advice of plan actuaries. Future results are impacted by these assumptions including the accrued benefit obligation and current service cost. See Note 23 for significant benefit plan assumptions.

(ii) Provisions and Contingencies

Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*. IAS 37 requires that a provision be recognized where there is a present obligation as a result of a past event, it is probable that transfer of economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation. Key assumptions in measuring recorded provisions include the timing and amount of future payments and the discount rate applied in valuing the provision.

(iii) Financial Instruments

The Company enters into financial instrument arrangements which require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, including whether those embedded derivatives meet the criteria to be separated from their host contract, in accordance with IFRS 9, *Financial Instruments*. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable, and for embedded derivatives, whether the economic risks and characteristics are not closely related to the host contract and a separate instrument with the same terms would meet the definition of a derivative on a standalone basis.

Valuation techniques are used in measuring the fair value of financial instruments when active market quotes are not available. Valuation of the Company’s financial instruments is based in part on forward prices which are volatile and therefore the actual realized value may differ from management’s estimates.

(iv) Right-of-Use Leases

The Company enters into long-term energy purchase agreements that may be considered to be or contain a lease. In making this determination, judgment is required to determine whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payment. The Company’s incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these options.

(v) Property, Plant and Equipment and Intangible Assets

Estimation and judgment are involved in determining useful lives and related depreciation and amortization of property, plant and equipment and intangible assets. Estimated useful lives are determined based upon the anticipated physical life of the asset, past experience with similar assets, industry averages and expectations about future events that could impact the life of the asset. Estimated useful lives are reviewed annually to ensure their reasonableness (Note 3(e) and 3(f)). The Company periodically conducts depreciation studies to assess asset useful lives.

In addition, significant judgment and estimation are required in determining the allocation of costs among components of major assets that are placed in service.

(vi) Rate Regulation

When a regulatory account has been or will be applied for, and, in management's estimate, acceptance of deferral treatment by the British Columbia Utilities Commission (BCUC), and recovery in future rates is considered probable, BC Hydro defers such costs in advance of a final order from the BCUC. In assessing whether deferral approval and collection in future rates is probable management considers factors such as past precedents, magnitude of the costs, impact on rates, legal enquiries, regulatory framework for cost recovery, and political environment. If the BCUC subsequently denies the application for regulatory treatment, the deferred amount is recognized immediately in comprehensive income.

Note 3: Material Accounting Policies

(a) Rate Regulation

BC Hydro is regulated by the BCUC and both entities are subject to directives and directions issued by the Province. BC Hydro's rates are set on a cost of service basis. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

In January 2014, the IASB issued an interim standard, IFRS 14, *Regulatory Deferral Accounts*, which provides guidance on accounting for the effects of rate regulation under IFRS. This guidance allows entities that conduct rate-regulated activities to continue to recognize regulatory deferral accounts. BC Hydro has elected to adopt IFRS 14 in its consolidated financial statements. The interim standard is only intended to provide temporary guidance until the IASB completes its comprehensive project on rate-regulated activities. IFRS 14 remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory orders regarding the Company's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on the Company's consolidated statements of financial position, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on orders from the BCUC. In the absence of rate-regulation, these amounts would be included in comprehensive income.

BC Hydro capitalizes as a regulatory asset, all or part of an incurred cost that would otherwise be charged to net income or other comprehensive income (OCI) if it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes and the future rates and revenue approved by the BCUC will permit recovery of that incurred cost. Regulatory liabilities are recognized for certain gains or other reductions of net allowable costs for adjustment of future rates as determined by the BCUC. In the event that the recovery of these asset balances is assessed to no longer be probable based on management's judgment or the refund of these liability balances is no longer required, the balances are recorded in the Company's consolidated statements of comprehensive income in the period when the assessment is made.

Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the consolidated statement of financial position, and are separately disclosed on the consolidated statements of comprehensive income as net movements in regulatory balances related to net income (loss) or net movements in regulatory balances related to other comprehensive income (loss). The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the BCUC's regulations and orders.

(b) Revenues

The Company recognizes revenue when it transfers control over a promised good or service, which constitutes a performance obligation under the contract, to a customer and where the Company is entitled to consideration as a result of completion of the performance obligation. Depending on the terms of the contract with the customer, revenue recognition can occur at a point in time or over time. When a performance obligation is satisfied, revenue is measured at the transaction price that is allocated to that performance obligation, net of any customer credits issued. Amounts received from customers in advance of the performance obligation are recognized as unearned revenue until the performance obligation is satisfied.

Domestic revenues comprise sales to customers within the province of British Columbia, sales that are surplus to domestic load requirements, and certain sales of energy outside the province that are under long-term contracts. Sales outside the province besides those described above are classified as Trade revenue.

A significant portion of the Company's revenue is generated from providing electricity goods and services. Revenue is recognized over time generally using output measure or progress (i.e., kilowatt hours delivered) as the Company's customers simultaneously receive and consume the electricity goods and services as it is provided. Revenue is determined on the basis of billing cycles and includes accruals for electricity deliveries not yet billed.

The Company recognizes a financing component where the timing of payment from the customer differs from the Company's performance under the contract and where that difference is the result of the Company financing the transfer of goods and services.

Energy trading contracts that meet the definition of a financial or non-financial derivative are accounted for at fair value whereby any realized gains and losses and unrealized changes in the fair value are recognized in trade revenues in the period of change. Realized and unrealized changes in the fair value of these contracts are accounted for under IFRS 9, *Financial Instruments* (Note 3(k)).

Energy trading and other contracts which do not meet the definition of a derivative are accounted for on an accrual basis whereby the realized gains and losses are recognized as revenue as the contracts are settled. Such contracts are considered to be settled when control of products and services are transferred to the buyer and performance obligation is satisfied.

(c) Finance Costs and Recoveries

Finance costs are comprised of interest expense on borrowings, accretion expense on provisions and other long-term liabilities, net interest on net defined benefit obligations, interest on lease liabilities, foreign exchange losses and realized and unrealized interest and foreign exchange hedging instrument losses that are recognized in the statement of comprehensive income, excluding energy trading contracts. All borrowing costs are recognized using the effective interest rate method.

Finance costs exclude borrowing costs attributable to the construction of qualifying assets, which are assets that take six months or more to prepare for their intended use.

Finance recoveries comprises of income earned on sinking fund investments held for the redemption of long-term debt, foreign exchange gains and realized and unrealized interest and foreign exchange hedging instrument gains that are recognized in the statement of comprehensive income, excluding energy trading contracts.

(d) Foreign Currency

Foreign currency transactions are translated into the respective functional currencies of BC Hydro and its subsidiaries, using the exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies at the reporting date are translated to the functional currency at the exchange rate in effect at that date. The foreign currency gains or losses on monetary items is the difference between the amortized cost in the functional currency at the beginning of the period, adjusted for effective interest and payments during the period, and the amortized cost in the foreign currency translated at the exchange rate at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

For purposes of consolidation, the assets and liabilities of Powerex, whose functional currency is the U.S. dollar, are translated to Canadian dollars using the rate of exchange in effect at the reporting date. Revenue and expenses of Powerex are translated to Canadian dollars at exchange rates at the date of the transactions. Foreign currency differences resulting from translation of the accounts of Powerex are recognized directly in other comprehensive income and are accumulated in the cumulative translation reserve. Foreign exchange gains or losses arising from a monetary item receivable from or payable to Powerex, the settlement of which is neither planned nor likely in the foreseeable future and which in substance is considered to form part of a net investment in Powerex by BC Hydro are recognized directly in other comprehensive income in the cumulative translation reserve.

(e) Property, Plant and Equipment

(i) Recognition and Measurement

Property, plant and equipment in service are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour and any other costs directly attributable to bringing the asset into service. The cost of dismantling and removing an item of property, plant and equipment and restoring the site on which it is located is estimated and capitalized only when, and to the extent that, the Company has a legal or constructive obligation to dismantle and remove such asset. Property, plant and equipment in service include the cost of plant and equipment financed by contributions in aid of construction. Borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset are capitalized as part of the cost of the qualifying asset. Upon retirement or disposal, any gain or loss is recognized in the statement of comprehensive income.

Unfinished construction consists of the cost of property, plant and equipment that is under construction or not ready for service. Costs are transferred to property, plant and equipment in service when the constructed asset is capable of operation in a manner intended by management.

(ii) Subsequent Costs

The cost of replacing a component of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the component will flow to the Company, and its cost can be measured reliably. The carrying amount of the replaced component is derecognized. The costs of property, plant and equipment maintenance are recognized in the statement of comprehensive income as incurred.

(iii) Depreciation

Property, plant and equipment in service are depreciated over the expected useful lives of the assets, using the straight-line method. When major components of an item of property, plant and equipment have different useful lives, they are accounted for as separate items of property, plant and equipment.

The expected useful lives, in years, of the Company’s main classes of property, plant and equipment are:

Generation	15 – 100
Transmission	20 – 75
Distribution	20 – 60
Buildings	5 – 65
Equipment & Other	3 – 35

The expected useful lives and residual values of items of property, plant and equipment are reviewed annually.

Depreciation of an item of property, plant and equipment commences when the asset is available for use and ceases at the earlier of the date the asset is classified as held for sale and the date the asset is derecognized.

(f) Intangible Assets

Intangible assets are recorded at cost less accumulated amortization and accumulated impairment losses. Land rights associated with statutory rights of way acquired from the Province that have indefinite useful lives are not subject to amortization. Intangible assets with finite useful lives are amortized over their expected useful lives on a straight line basis. These assets are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be fully recoverable.

The expected useful life for software is 2 to 10 years. Amortization of intangible assets commences when the asset is available for use and ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized.

(g) Asset Impairment

(i) Financial Assets

Financial assets, other than those measured at fair value (note 3(k)), are assessed at each reporting date to determine whether there is impairment. The Company accounts for impairment of financial assets based on a forward-looking expected credit loss model under IFRS 9, *Financial Instruments*. The expected-loss impairment model requires an entity to recognize the expected credit losses (ECL) when financial instruments are initially recognized and to update the amount of ECL recognized at each reporting date to reflect changes in the credit risk of the financial instruments. ECL's are measured as the difference in the present value of the contractual cash flows due to the Company under the contract and the cash flows that Company expects to receive.

For accounts receivable without a significant financing component, the Company applies the simplified approach for determining expected credit losses, which requires the Company to determine the lifetime expected losses for all accounts receivable and accrued revenue. For a non-current receivable with a significant financing component, the Company measures the expected credit loss at an amount equal to the 12-month expected credit loss at initial recognition. If the credit risk has increased significantly since initial recognition, the Company measures the expected credit loss at an amount equal to the lifetime expected credit loss. The expected lifetime credit loss provision and 12-month expected credit loss is based on historical counterparty default rates, third party default probabilities and credit ratings, and is adjusted for relevant forward looking information specific to the counterparty, when required.

(ii) Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated annually.

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of identifiable assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the cash-generating unit, or CGU). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. All of BC Hydro's assets form one CGU for the purposes of testing for impairment.

An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income. Impairment losses recognized in respect of a CGU are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

(h) Cash and Cash Equivalents

Cash and cash equivalents include unrestricted cash and units of a money market fund (short-term investments) that are redeemable on demand and are carried at amortized cost and fair value, respectively.

(i) Restricted Cash

Restricted cash includes cash balances which the Company does not have immediate access to as they have been pledged to counterparties as security for investments or trade obligations. These balances are available to the Company only upon settlement of the underlying obligations.

(j) Inventories

Inventories are comprised primarily of natural gas, materials and supplies, and environmental products that include certain carbon products. Natural gas and certain carbon product inventory are valued at fair value less costs to sell and is included in Level 2 of the fair value hierarchy (refer to Note 10).

Materials and supplies and other environmental products inventories are valued at the lower of cost determined on a weighted average basis and net realizable value. The cost of materials and supplies comprises all costs of purchase, costs of conversion and other directly attributable costs incurred in bringing the inventories to their present location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated selling expenses.

(k) Financial Instruments

(i) Financial Instruments – Recognition and Measurement

All financial instruments are measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on which of the following categories the financial instrument has been classified as: fair value through profit or loss (FVTPL), and those measured at amortized cost. 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. All derivative instruments are categorized as FVTPL unless they are designated as accounting hedges.

Transaction costs are expensed as incurred for financial instruments classified or designated as fair value through profit or loss. For other financial instruments, transaction costs are included in the carrying amount. All regular-way purchases or sales of financial assets are accounted for on a settlement date basis.

Financial assets and financial liabilities classified as FVTPL are subsequently measured at fair value with changes in those fair values recognized in net income in the period of change. Financial assets and liabilities are measured at amortized cost if the business model is to hold the instrument for collection or payment of contractual cash flows and those cash flows are solely principal and interest. If the business model is not to hold the instruments, it is classified as FVTPL. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses in the impairment of financial assets.

(ii) Classification and Measurement of Financial Instruments

Short-term investments	FVTPL
Derivatives	FVTPL
Cash	Amortized cost
Restricted cash	Amortized cost
Accounts receivable and other receivable	Amortized cost
US dollar sinking funds	Amortized cost
Accounts payable and accrued liabilities	Amortized cost
Short-term borrowings	Amortized cost
Long-term debt	Amortized cost
Lease liabilities	Amortized cost
First Nation liabilities and Other liabilities presented in Other long-term liabilities	Amortized cost

(iii) Fair Value

The fair value of financial instruments reflects changes in the level of commodity market prices, interest rates, foreign exchange rates and credit risk. Fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable willing parties who are under no compulsion to act.

Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of future prices and foreign exchange rates, time value of money, counterparty and own credit risk, and volatility. The assumptions used in establishing fair value amounts could differ from actual prices and the impact of such variations could be material. In certain circumstances, valuation inputs are used that are not based on observable market data but based on internally developed valuation models which are based on models and techniques generally recognized as standard within the energy industry.

(iv) Inception Gains and Losses

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition, as defined by its transaction price, and the fair value calculated by a valuation technique or model (inception gain or loss). In addition, the Company's inception gain or loss on a contract may arise as a result of embedded derivatives which are recorded at fair value, with the remainder of the contract recorded on an accrual basis. In these circumstances, the unrealized inception gain or loss is deferred and amortized into income over the full term of the underlying financial instrument. Additional information on deferred inception gains and losses is disclosed in Note 24.

(v) Derivative Financial Instruments

The Company may use derivative financial instruments to manage interest rate and foreign exchange risks related to debt and to manage risks related to electricity and natural gas commodity transactions.

Interest rate and foreign exchange related derivative instruments that are not designated as hedges, are classified as FVTPL whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income in the period of change. For debt management activities, the related gains or losses are included in finance charges. The Company's policy is to not utilize interest rate and foreign exchange related derivative financial instruments for speculative purposes.

Commodity derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices. Commodity derivatives that are not designated as hedges are classified as FVTPL whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. Gains or losses are included in trade revenues.

(vi) Hedges

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net income. Changes in the fair value of the hedged item attributed to the hedged risk, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net income. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship, using the effective interest method of amortization.

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. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. When hedge accounting is discontinued the cumulative gain or loss previously recognized in accumulated other comprehensive income remains there until the forecasted transaction occurs. When the hedged item is a non-financial asset or liability, the amount recognized in accumulated other comprehensive income is transferred to the carrying amount of the asset or liability when it is recognized. In other cases, the amount recognized in accumulated other comprehensive income is transferred to net income in the same period that the hedged item affects net income.

Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, the hedging relationship is discontinued, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

(l) Investments Held in Sinking Funds

Investments held in sinking funds are held as individual portfolios and are classified as amortized cost. Securities included in an individual portfolio are recorded at cost, adjusted by amortization of any discounts or premiums arising on purchase, on a yield basis over the estimated term to settlement of the security. Realized gains and losses are included in finance charges.

(m) Unearned Revenues

Unearned revenues consist principally of amounts received under the agreement relating to the Skagit River, Ross Lake and the Seven Mile Reservoir on the Pend d'Oreille River (collectively the Skagit River Agreement) and other amounts received from customers for performance obligations which have not been performed.

Under the Skagit River Agreement, the Company has committed to deliver a predetermined amount of electricity each year to the City of Seattle for an 80 year period ending in fiscal 2066 in return for annual payments of approximately US$22 million for a 35 year period ending in 2021 and US$100,000 (adjusted for inflation) for the remaining 45 year period ending in 2066. The amounts received under the agreement are deferred and included in income on an annuity basis over the electricity delivery period ending in fiscal 2066. As a result of the upfront consideration received under the Skagit River Agreement, in determining the transaction price, the promised amount of consideration is adjusted for the effects of the time value of money (i.e., significant financing component). The application of the significant financing component requirement results in the recognition of interest expense over the financing period and a higher amount of revenue.

(n) Government Grants

The Company recognizes government grants when there is reasonable assurance that any conditions attached to the grant will be met and the grant will be received. Government grants related to assets are deducted from the carrying amount of the related asset and recognized in profit or loss over the life of the related asset. Grants that compensate the Company for expenses incurred are recognized in profit or loss as an offset against the originating expense in the same period in which the expenses are recognized. Non-monetary grants are recognized on the cost basis at a nominal amount.

(o) Contributions in Aid of Construction

Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity. These amounts are recognized into revenue over the term of the agreement with the customer, or over the expected useful life of the related assets when the associated contracts do not have a finite period over which service is provided.

(p) Post-Employment Benefits

The cost of pensions and other post-employment benefits earned by employees is actuarially determined using the projected accrued benefit method pro-rated on service and management's best estimate of mortality, salary escalation, retirement ages of employees and expected health care costs. The net interest for the period is determined by applying the same market discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability at the beginning of the annual period, taking into account any changes in the net defined benefit asset or liability during the period as a result of current service costs, contributions and benefit payments. The market discount rate is determined based on the market interest rate at the end of the year on high-quality corporate debt instruments that match the timing and amount of expected benefit payments.

Past service costs arising from plan amendments and curtailments are recognized in net income immediately. A plan curtailment will result if the Company has demonstrably committed to a significant reduction in the expected future service of active employees or a significant element of future service by active employees no longer qualifies for benefits. A curtailment is recognized when the event giving rise to the curtailment occurs.

The net interest costs on the net defined benefit plan liabilities arising from the passage of time are included in finance charges. The Company recognizes actuarial gains and losses immediately in other comprehensive income.

(q) Provisions

A provision is recognized if the Company has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation and a reliable estimate of the obligation can be determined. For obligations of a long-term nature, provisions are measured at their present value by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability except in cases where future cash flows have been adjusted for risk.

Decommissioning Obligations

Decommissioning obligations are legal and constructive obligations associated with the retirement of long-lived assets. A liability is recorded at the present value of the estimated future costs based on management's best estimate. When a liability is initially recorded, the Company capitalizes the costs by increasing the carrying value of the asset unless the asset is fully depreciated. The increase in net present value of the provision for the expected cost is included in finance costs as accretion (interest) expense. Adjustments to the provision made for changes in timing, amount of cash flow and discount rates are capitalized and amortized over the useful life of the associated asset. Actual costs incurred upon settlement of a decommissioning obligation are charged against the related liability. Any difference between the actual costs incurred upon settlement of the decommissioning obligation and the recorded liability is recognized in net income at that time.

Environmental Expenditures and Liabilities

Environmental expenditures are expensed as part of operating activities, unless they constitute an asset improvement or act to mitigate or prevent possible future contamination, in which case the expenditures are capitalized and amortized to income. Environmental liabilities arising from a past event are accrued when it is probable that a present legal or constructive obligation will require the Company to incur environmental expenditures.

Legal

The Company recognizes legal claims as a provision when it is probable that there will be a future outflow of resources required to settle the claim against the Company and the amount of the settlement can be reliably measured. Management obtains the advice of its legal counsel in determining the likely outcome and estimating the expected costs associated with legal claims. Further information regarding lawsuits in progress is disclosed in Note 26.

(r) Leases

At inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether the contract involves the use of an identified asset, whether the Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use, and has the right to direct the use of the asset. At inception or on reassessment of a contract that contains a lease component, consideration is allocated to each lease component within the contract on the basis of its relative stand-alone prices.

As a lessee, the Company recognizes a right-of-use asset and a 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 decommissioning and restoration costs, less any lease incentives received.

The right-of-use asset is subsequently depreciated from the commencement date to the earlier of the end of the lease term, or the end of the useful life of the asset. In addition, the right-of-use asset may be reduced due to impairment losses, if any, and adjusted for re-measurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the incremental borrowing rate.

Lease payments included in the measurement of the lease liability are comprised of:

i) Fixed payments, including in-substance fixed payments, less any lease incentives receivable;

ii) Variable lease payments that depend on an index or a rate, initially measured using the index or rate as at the commencement date;

iii) Amounts expected to be payable under a residual value guarantee;

iv) Exercise prices of purchase options if reasonably certain the option will be exercised; and

v) Payments of penalties for terminating the lease, if the lease term reflects the lessee exercising an option to terminate the lease.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company’s estimate or assessment of the amount expected to be payable under a residual value guarantee, purchase, extension or termination option.

When the lease liability is re-measured, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

Lease modifications are accounted for as separate leases when they increase the scope of the lease and the consideration is commensurate with the stand-alone price. Other lease modifications result in a remeasurement of the lease liability using a revised discount rate, with a corresponding adjustment to the right-of-use asset or recognition in profit or loss where the modification decreases the lease scope.

Variable lease payments not included in the initial measurement of the lease liability are charged directly to the consolidated statement of comprehensive income as an expense.

The Company elected to use the following practical expedients under IFRS 16:

(i) The Company has elected not to separate non-lease components and account for the lease and non-lease components as a single lease component for leases pertaining to generating assets (including long-term energy purchase agreements).

(ii) The Company has elected not to recognize right-of-use assets and lease liabilities for short-term leases that have a lease term of 12 months or less and leases of low-value assets.

(s) Taxes

The Company is a Crown corporation and therefore no Canadian provincial or federal income tax is payable. However, the Company pays provincial and local government taxes and grants in lieu of property taxes to municipalities, regional districts, and rural area jurisdictions. In addition, Powerex, a subsidiary of BC Hydro, pays taxes relating to trading and operating activities in the United States.

(t) New Standards and Amendments Not Yet Adopted

A number of amendments to standards and interpretations and one new standard, are not yet effective for the year ended March 31, 2026, and have not been applied in preparing these consolidated financial statements. The following new and amended standards become effective for the Company's annual periods beginning on or after the dates noted below:

- Amendments to IFRS 7, *Financial Instruments: Disclosures* (effective April 1, 2026)
- Amendments to IFRS 9, *Financial Instruments* (effective April 1, 2026)
- Amendments to IAS 21, *The Effects of Changes in Foreign Exchange Rates* (effective April 1, 2027)
- IFRS 18, *Presentation and Disclosure in Financial Statements* (effective April 1, 2027)

The Company is currently assessing the effect of the amended standards on the consolidated financial statements. The Company is currently assessing the impact of the new standard, IFRS 18, on its consolidated financial statements and note disclosures. The standard introduces new defined subtotals and requires disclosure of management defined performance measures (MPMs). The Company expects changes to the structure of its statement of comprehensive income but does not expect IFRS 18 to affect recognition or measurement of assets and liabilities.

Note 4: Revenues

Disaggregated Revenue

The Company disaggregates revenue by revenue types and customer class, which are considered to be the most relevant revenue information for management to consider in allocating resources and evaluating performance.

(in millions)		**2026**		2025
Domestic				
Residential	**$**	**2,490**	$	2,405
Light industrial and commercial		**2,143**		2,061
Large industrial		**1,026**		947
Other sales		**691**		636
Total Domestic		**6,350**		6,049
Total Trade[1]		**1,244**		1,429
Total Revenue	**$**	**7,594**	$	7,478

[1] Includes revenue of $490 million recognized under IFRS 9, *Financial Instruments* (2025 - $504 million) and revenue of $46 million recognized under IAS 2, Inventories (2025 - $20 million).

Contract Balances

The Company does not have any contract assets which constitute consideration receivable from a customer that is conditional on the Company's future performance. The current and non-current receivable balances from customers as at March 31, 2026 was $940 million (2025 - $762 million).

Contract liabilities represent payments received for performance obligations which have not been fulfilled.

The following table reconciles the items included in the contract liabilities balance:

(in millions)		**March 31, 2026**		March 31, 2025
Unearned revenues (Note 21)	**$**	**350**	$	358
Contributions in aid (Note 21)		**3,026**		2,834
Customer deposits		**130**		102
	$	**3,506**	$	3,294

The following table reconciles the changes in the contract liabilities balances during the years ended March 31, 2026 and 2025:

(in millions)		Contract Liabilities
Balance at April 1, 2024	**$**	**3,286**
Revenue recognized that was included in the contract liability balance at the beginning of the year		(166)
Increases due to cash received, excluding amounts recognized as revenue during the year		478
Other[1]		(304)
Balance at March 31, 2025		**3,294**
Revenue recognized that was included in the contract liability balance at the beginning of the year		(204)
Increases due to cash received, excluding amounts recognized as revenue during the year		388
Other[1]		28
Balance at March 31, 2026	**$**	**3,506**

[1] Other includes finance charges, foreign exchange adjustments, and Energy Affordability Credits applied to customer bills.

Remaining Performance Obligations

The following table includes revenue expected to be recognized in the future related to the performance obligations that are unsatisfied (or partially unsatisfied) as at March 31, 2026:

(in millions)		Less than 1 year		Between 1 and 5 years		More than 5 years		Total
Contributions in aid	$	75	$	300	$	2,651	$	3,026
Skagit River Agreement		30		119		1,039		1,188
Other		96		170		30		296
	$	201	$	589	$	3,720	$	4,510

The Company elected to use the performance obligation practical expedients whereby the performance obligation is not disclosed for the following:

(i) Where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance to date, revenue is recognized in the amount to which the Company has a right to invoice, or

(ii) Where the remaining performance obligations have an original expected duration of one year or less.

Note 5: Operating Expenses

(in millions)		**2026**		2025
Electricity and gas purchases	**$**	**2,118**	$	2,209
Water rentals		**336**		294
Transmission charges		**295**		361
Personnel expenses		**979**		916
Materials and external services		**1,217**		1,100
Amortization and depreciation (Note 7)		**1,354**		1,200
Grants and taxes		**336**		326
Other costs, net of recoveries		**163**		98
Capitalized costs		**(108)**		(105)
	$	**6,690**	$	6,399

Note 6: Finance Charges

(in millions)		**2026**		2025
Interest on debt	**$**	**1,173**	$	1,119
Interest on lease liabilities		**43**		44
Interest on defined benefit plan obligations (Note 23)		**41**		35
Losses (gains) on derivative financial instruments (Note 24)		**(307)**		154
Capitalized interest		**(125)**		(335)
Other		**39**		77
	$	**864**	$	1,094

The capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 3.5 per cent (2025 - 3.6 per cent).

Note 7: Amortization and Depreciation

(in millions)		**2026**		2025
Depreciation of property, plant and equipment (Note 11)	**$**	**1,180**	$	1,033
Depreciation of right-of-use assets (Note 12)		**93**		86
Amortization of intangible assets (Note 13)		**81**		81
	$	**1,354**	$	1,200

Note 8: Cash and Cash Equivalents and Restricted Cash

(in millions)		**March 31, 2026**		March 31, 2025
Cash	**$**	**60**	$	58
Short-term investments		**62**		78
Restricted Cash		**54**		35
	$	**176**	$	171

Note 9: Accounts Receivable and Accrued Revenue

(in millions)		**March 31, 2026**		March 31, 2025
Accounts receivable	**$**	**397**	$	365
Accrued revenue		**316**		255
Other		**285**		200
	$	**998**	$	820

Accrued revenue represents revenue for electricity delivered and not yet billed.

Note 10: Inventories

(in millions)		**March 31, 2026**		March 31, 2025
Materials, Supplies, and Environmental Products	**$**	**327**	$	301
Natural Gas and Certain Carbon products		**117**		151
	$	**444**	$	452

There were no materials, supplies, and environmental products inventory impairments during the years ended March 31, 2026 and 2025. Natural gas and certain carbon products inventory that are held for trading are measured at fair value less costs to sell and are therefore not subject to impairment testing.

Inventories recognized as an expense during the year amounted to $184 million (2025 - $182 million).

Note 11: Property, Plant, and Equipment

(in millions)	Generation	Transmission	Distribution	Land & Buildings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at April 1, 2024	$ 10,645	$ 9,108	$ 8,527	$ 984	$ 1,156	$ 15,253	$ 45,673
Net additions	13,396	376	804	68	148	(10,866)	3,926
Disposals and retirements	(13)	(19)	(52)	-	(70)	(13)	(167)
Balance at March 31, 2025	24,028	9,465	9,279	1,052	1,234	4,374	49,432
Net additions	1,152	584	1,020	133	184	754	3,827
Disposals and retirements	(18)	(22)	(55)	(3)	(35)	(37)	(170)
Balance at March 31, 2026	$ 25,162	$ 10,027	$ 10,244	$ 1,182	$ 1,383	$ 5,091	$ 53,089
Accumulated Depreciation							
Balance at April 1, 2024	$ (1,746)	$ (1,615)	$ (1,490)	$ (196)	$ (518)	$ -	$ (5,565)
Depreciation expense	(358)	(260)	(269)	(36)	(110)	-	(1,033)
Disposals and retirements	12	12	18	-	69	-	111
Balance at March 31, 2025	(2,092)	(1,863)	(1,741)	(232)	(559)	-	(6,487)
Depreciation expense	(471)	(264)	(292)	(37)	(116)	-	(1,180)
Disposals and retirements	15	15	21	2	32	-	85
Balance at March 31, 2026	$ (2,548)	$ (2,112)	$ (2,012)	$ (267)	$ (643)	$ -	$ (7,582)
Net carrying amounts							
At March 31, 2025	$ 21,936	$ 7,602	$ 7,538	$ 820	$ 675	$ 4,374	$ 42,945
At March 31, 2026	$ 22,614	$ 7,915	$ 8,232	$ 915	$ 740	$ 5,091	$ 45,507

(i) During the year ended March 31, 2026, $938 million (2025 - $13.20 billion) in assets related to the Site C Project were put in-service and transferred from the Unfinished Construction category to Generation.

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1.39 billion (2025 - $1.32 billion) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2026 was $38 million (2025 - $36 million).

(iii) The Company received government grants arising from the Columbia River Treaty related to three dams built by the Company in the mid-1960s to regulate the flow of the Columbia River. The grants were made to assist in financing the construction of the dams. The grants were deducted from the carrying amount of the related dams. In addition, the Company received, in the current year and prior years, government grants for the construction of transmission lines and electric vehicle infrastructure and has deducted the grants received from the cost of the asset. BC Hydro received and earned government grants of $110 million during the year ended March 31, 2026 (2025 - $72 million) which were deducted from the cost of the assets.

(iv) The Company has contractual commitments to spend $1.64 billion on major property, plant and equipment projects (on individual projects greater than $20 million) as at March 31, 2026.

Note 12: Right-of-Use Assets

(in millions)	Long-term energy purchase agreements	Property	Equipment/ Other	Total
Cost				
Balance at April 1, 2024	$ 1,739	$ 79	$ 4	$ 1,822
Net additions	52	(1)	5	56
Disposals, retirements and other	-	2	-	2
Balance at March 31, 2025	1,791	80	9	1,880
Net additions	40	(6)	10	44
Disposals, retirements and other	-	(1)	(2)	(3)
Balance at March 31, 2026	$ 1,831	$ 73	$ 17	$ 1,921
Accumulated Depreciation				
Balance at April 1, 2024	$ (573)	$ (36)	$ (4)	$ (613)
Depreciation expense	(80)	(6)	-	(86)
Disposals, retirements and other	-	(1)	-	(1)
Balance at March 31, 2025	(653)	(43)	(4)	(700)
Depreciation expense	(89)	(4)	-	(93)
Disposals, retirements and other	-	1	3	4
Balance at March 31, 2026	$ (742)	$ (46)	$ (1)	$ (789)
Net carrying amounts				
At March 31, 2025	$ 1,138	$ 37	$ 5	$ 1,180
At March 31, 2026	$ 1,089	$ 27	$ 16	$ 1,132

Refer to Note 20 for additional information on right-of-use assets and lease liabilities.

Note 13: Intangible Assets

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at April 1, 2024	$ 341	$ 180	$ 599	$ 1	$ 80	$ 1,201
Net additions	34	15	66	-	(15)	100
Disposals, retirements, and other	-	(28)	(17)	(1)	(9)	(55)
Balance at March 31, 2025	375	167	648	-	56	1,246
Net additions	7	8	46	10	25	96
Disposals, retirements, and other	-	8	(20)	-	-	(12)
Balance at March 31, 2026	$ 382	$ 183	$ 674	$ 10	$ 81	$ 1,330
Accumulated Amortization						
Balance at April 1, 2024	$ (6)	$ (134)	$ (420)	$ -	$ -	$ (560)
Amortization expense	(1)	(16)	(64)	-	-	(81)
Disposals, retirements, and other	-	28	18	-	-	46
Balance at March 31, 2025	(7)	(122)	(466)	-	-	(595)
Amortization expense	(1)	(16)	(63)	(1)	-	(81)
Disposals, retirements, and other	-	(8)	20	-	-	12
Balance at March 31, 2026	$ (8)	$ (146)	$ (509)	$ (1)	$ -	$ (664)
Net carrying amounts						
At March 31, 2025	$ 368	$ 45	$ 182	$ -	$ 56	$ 651
At March 31, 2026	$ 374	$ 37	$ 165	$ 9	$ 81	$ 666

Land rights consist primarily of statutory rights of way acquired from the Province in perpetuity. Substantially all of these land rights have indefinite useful lives and are not subject to amortization. These land rights are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be recoverable.

Note 14: Other Non-Current Assets

(in millions)		**March 31, 2026**		March 31, 2025
Non-current receivables	**$**	**104**	$	114
Other		**125**		40
	$	**229**	$	154

Non-Current Receivables

Included in the non-current receivables balance are $89 million of receivables (2025 - $98 million) from a vendor to aid in the construction of a transmission system. The contributions are to be received in 16 annual payments of approximately $11 million, adjusted for inflation. The fair value of the receivable was initially measured using an estimated inflation rate and a 4.6 per cent discount rate.

Note 15: Sinking Funds

Investments held in sinking funds are held by the Trustee (the Minister of Finance for the Province) for the redemption of long-term debt. The sinking fund balances include the following investments:

(in millions)	**March 31, 2026**			March 31, 2025		
		Carrying Value	**Weighted Average Effective Rate[1]**		Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$**	**48**	**4.7 %**	$	154	4.5 %
Other provincial government and crown corporation bonds		**5**	**4.4 %**		67	4.4 %
Money market funds		**2**	**-**		56	-
Other		**1**	**-**		2	-
	$	**56**		$	279	
Less: Current portion		**-**			(225)	
Non-current sinking funds	**$**	**56**		$	54	

[1]Rate calculated on market yield to maturity.

Effective December 2005, all sinking fund payment requirements on new and outstanding debt were removed. The existing sinking funds relate to debt that matures in fiscal 2037.

Note 16: Rate Regulation

Regulatory Accounts

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. In the absence of rate regulation, these amounts would be reflected in total comprehensive income. The net movement in regulatory balances related to total comprehensive income is as follows:

(in millions)		**2026**		2025
Net increase in regulatory balances related to net income	**$**	**681**	$	602
Net increase (decrease) in regulatory balances related to OCI		**(427)**		66
	$	**254**	$	668

For each regulatory account, the amount reflected in the net change column in the following regulatory tables represents the impact on comprehensive income for the applicable year. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

(in millions)	*As at April 1 2025*	*Addition / (Reduction)*	*Interest* [A]	*Amortization*	*Net Change*	***As at March 31 2026***	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ 167	$ 55	$ 5	$ (121)	$ (61)	**$ 106**	Note B
Non-Heritage Deferral	1,494	65	37	(1,083)	(981)	**513**	Note B
Load Variance	88	123	4	(64)	63	**151**	Note B
Demand-Side Management	936	240	-	(121)	119	**1,055**	1-15
Debt Management	33	(33)	-	-	(33)	**-**	2-34
First Nations Provisions & Costs	479	19	-	(18)	1	**480**	1-8 Note F
Site C	511	1	18	(23)	(4)	**507**	Note D
CIA Amortization	53	(5)	-	-	(5)	**48**	14
Environmental Provisions & Costs	207	(2)	1	(33)	(34)	**173**	Note E, F
Smart Metering & Infrastructure	88	-	3	(25)	(22)	**66**	3
Inflationary Pressures	113	-	3	(59)	(56)	**57**	Note E
IFRS Pension	268	-	-	(38)	(38)	**230**	6
IFRS Property, Plant & Equipment	944	-	-	(31)	(31)	**913**	26-35
Total Finance Charges	115	(40)	-	(75)	(115)	**-**	Note E
Cloud Costs	111	80	5	(18)	67	**178**	1-11
Project Write-off Costs	55	19	2	(23)	(2)	**53**	Note E
Site C Variance Costs	117	15	5	-	20	**137**	Note I
Other Regulatory Accounts	151	69	4	(50)	23	**174**	Note H
Total Regulatory Assets	5,930	606	87	(1,782)	(1,089)	**4,841**	
Regulatory Liabilities							
Trade Income Deferral	1,856	(167)	42	(1,346)	(1,471)	**385**	Note C
Rate Smoothing	446	(1)	12	(238)	(227)	**219**	Note E
Debt Management	-	267	-	(11)	256	**256**	2-34
Biomass Energy Program Variance	188	(46)	4	(136)	(178)	**10**	Note B
Low Carbon Fuel Credits Variance	84	(15)	2	(61)	(74)	**10**	Note B
Non-Current Pension Costs	730	344	-	(32)	312	**1,042**	1-13
PEB Current Pension Costs	85	-	-	(42)	(42)	**43**	Note E
Electric Vehicle Rebate	18	30	1	-	31	**49**	Note G
Total Finance Charges	-	16	-	15	31	**31**	Note E
Other Regulatory Accounts	3	86	-	(67)	19	**22**	Note H
Total Regulatory Liabilities	3,410	514	61	(1,918)	(1,343)	**2,067**	
Net Regulatory Asset	$ 2,520	$ 92	$ 26	$ 136	$ 254	**$ 2,774**	

(in millions)	*As at April 1 2024*	*Addition / (Reduction)*	*Interest* [A]	*Amortization*	*Net Change*	*As at March 31 2025*	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ 49	$ 106	$ 5	$ 7	$ 118	$ 167	Note B
Non-Heritage Deferral	1,092	187	49	166	402	1,494	Note B
Load Variance	11	75	-	2	77	88	Note B
Demand-Side Management	870	186	-	(120)	66	936	1-15
Debt Management	-	37	-	(4)	33	33	3-34
First Nations Provisions & Costs	474	21	-	(16)	5	479	1-9 Note F
Site C	502	(4)	19	(6)	9	511	Note D
CIA Amortization	58	(5)	-	-	(5)	53	15
Environmental Provisions & Costs	208	11	-	(12)	(1)	207	Note E, F
Smart Metering & Infrastructure	109	-	4	(25)	(21)	88	4
Inflationary Pressures	7	104	2	-	106	113	Note E
IFRS Pension	306	-	-	(38)	(38)	268	7
IFRS Property, Plant & Equipment	976	-	-	(32)	(32)	944	27-36
Total Finance Charges	88	39	-	(12)	27	115	Note E
Cloud Costs	47	61	3	-	64	111	1-12
Project Write-off Costs	48	8	2	(3)	7	55	Note E
Site C Variance Costs	-	115	2	-	117	117	Note I
Other Regulatory Accounts	108	71	3	(31)	43	151	Note H
Total Regulatory Assets	4,953	1,012	89	(124)	977	5,930	
Regulatory Liabilities							
Trade Income Deferral	1,736	55	65	-	120	1,856	Note C
Rate Smoothing	-	438	8	-	446	446	Note E
Debt Management	114	(128)	-	14	(114)	-	3-34
Biomass Energy Program Variance	127	36	6	19	61	188	Note B
Low Carbon Fuel Credits Variance	63	9	2	10	21	84	Note B
Non-Current Pension Costs	892	(191)	-	29	(162)	730	2-13
PEB Current Pension Costs	65	28	-	(8)	20	85	Note E
Electric Vehicle Rebate	71	(54)	1	-	(53)	18	Note G
Other Regulatory Accounts	33	(31)	1	-	(30)	3	Note H
Total Regulatory Liabilities	3,101	162	83	64	309	3,410	
Net Regulatory Asset	$ 1,852	$ 850	$ 6	$ (188)	$ 668	$ 2,520	

[A] As permitted by the BCUC, interest charges were accrued to certain regulatory account balances at BC Hydro's weighted average cost of debt which was 3.5 per cent for the year ended March 31, 2026 (2025 – 3.7 per cent).

[B] The balances in these regulatory accounts are recovered in rates through the Deferral Account Rate Rider (DARR), which is an additional charge or refund on customer bills and generally has a recovery period of 4 to 6 years. In its Order for the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC approved the requested DARR refund of 4.5 per cent (2025 – 2.5 per cent) for fiscal 2026, effective April 1, 2025, and a refund of 1.5 per cent for fiscal 2027.

[C] In its Order for the Fiscal 2026 to Fiscal 2027 Revenue Requirements Application, the BCUC approved recovery of the Trade Income Deferral Account balance through the DARR and the requested the DARR refund of 4.5 per cent for fiscal 2026, effective April 1, 2025, and a of refund 1.5 per cent for fiscal 2027. In fiscal 2025, the Trade Income Deferral Account balance was recovered through the Trade Income Rate Rider (TIRR) at an approved refund of 2.3 per cent, which is a separate additional charge or refund on customer bills.

[D] The Site C regulatory account balance commenced recovery in fiscal 2025. The balance is recovered over the forecasted weighted average expected useful life of the Site C assets, estimated at 86 years (2025 – 84 years) in the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*.

[E] The balances forecast to be in these accounts at the end of a test period are recovered over the next test period. A test period refers to the period covered by a revenue requirements application filing.

[F] The First Nations Provisions & Costs and Environmental Provisions & Costs regulatory accounts include both expenditures and provisions (costs to be incurred in future years). Actual expenditures are recovered over the term identified. The provision balance becomes recoverable at such time as expenditures are forecast to be incurred and transferred to the respective regulatory cost account.

[G] The Electric Vehicle Rebate regulatory account includes electric vehicle rebates, revenue from specified low carbon fuel credits, administration and marketing costs, and forecast interest. BC Hydro will request a refund mechanism to refund the revenue from specified low carbon fuel credits and cost of issuing electric vehicle rebates in the test period commencing in fiscal 2028. The administration and marketing costs, including forecast interest, are recovered over the next test period.

[H] Other Regulatory Accounts includes various accounts with recovery periods ranging from 1 to 100 years or that will be determined by the BCUC as part of a future regulatory proceeding.

[I] The recovery period for this account will be determined by the BCUC as part of a future regulatory proceeding.

Rate Regulation

On March 17, 2025, the Government of B.C. issued Order in Council No. 131 which under section 3 of the Utilities Commission Act enacted Direction No. 9 to the BCUC to, among other things, issue final orders approving various rate changes. In accordance with Direction No. 9, on March 26, 2025, the BCUC issued Order No. G-76-25 to approve the requested bill increases of 3.75 per cent (2025 – 2.3 per cent) for each of fiscal 2026 and fiscal 2027, which included a DARR refund of 4.5 per cent (2025 – 2.5 per cent) and 1.5 per cent for fiscal 2026 and fiscal 2027 respectively. In addition, the Order included the refund of the Trade Income Deferral Account in the Deferral Account Rate Rider, the establishment of a new Net Salvage Regulatory Account and recovery mechanisms for the Rate Smoothing Regulatory Account, the Inflationary Pressures Regulatory Account and the Electrification Customer Connections Regulatory Account.

Heritage Deferral Account

This account is intended to mitigate the impact of certain cost and revenue variances between the forecast costs and revenues in a revenue requirements application and actual costs and revenues associated with the Company’s hydroelectric and thermal generating facilities. The account balance is recovered through the DARR, which is an additional charge or refund on customer bills. In its Order for the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2026. The DARR table mechanism is a sliding scale that determines the level of the DARR based on the forecast net balance of the cost of energy variance accounts (i.e., the Heritage Deferral account, the Non-Heritage Deferral account, the Load Variance account, the Biomass Energy Program Variance account and the Low Carbon Fuel Credits Variance Regulatory Account). In response to the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC issued Order No. G-76-25, as directed by the Government of BC in Direction No. 9, that the Trade Income Deferral account be recovered through the DARR table mechanism with the cost of energy variance accounts for fiscal 2026 and 2027.

Non-Heritage Deferral Account

This account is intended to mitigate the impact of certain cost and revenue variances between the forecast costs and revenues in a revenue requirements application and actual costs and revenues related to items including all non-heritage energy costs (e.g., costs related to power acquisitions from Independent Power Producers). The account balance is recovered through the DARR, which is an additional charge or credit on customer bills.

Load Variance

This account is intended to capture the variance between planned and actual domestic customer load (i.e., customer demand). This account is categorized as one of BC Hydro's cost of energy variance accounts and has the same mechanisms for interest charges and recovery applied to it that are applicable to the Non-Heritage Deferral Account. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills.

Biomass Energy Program Variance

This account is intended to capture the variances between planned and actual energy purchase and load associated with Biomass energy purchases agreements. This account is categorized as one of BC Hydro's cost of energy variance accounts and has the same mechanisms for interest charges and recovery applied to it that are applicable to the Non-Heritage Deferral Account. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills.

Low Carbon Fuel Credits

This account is intended to capture the variances between planned and actual revenue from low carbon fuel credits. This account is categorized as one of BC Hydro's cost of energy variance accounts and has the same mechanisms for interest charges and recovery applied to it that are applicable to the Non-Heritage Deferral Account. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills.

Trade Income Deferral Account

This account is intended to mitigate the uncertainty associated with forecasting the net income of the Company's trade activities. The impact is to defer the difference between the Trade Income forecast in a revenue requirements application and actual Trade Income. In its Order for the *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application*, the BCUC directed BC Hydro, for fiscal 2025, to recover the Trade Income Deferral Account in rates, through the Trade Income Rate Rider (TIRR), which is a separate additional charge or credit on customer bills. In response to the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC issued Order No. G-76-25, as directed by the Government of BC in Direction No. 9, that the Trade Income Deferral account be recovered through the DARR table mechanism with the cost of energy variance accounts for fiscal 2026 and 2027.

Inflationary Pressures

On November 18, 2022, the Province issued Order in Council No. 571, which directed the BCUC to authorize BC Hydro to establish the Inflationary Pressures Regulatory Account and transfer $74 million from the Trade Income Deferral Account to the new account. It also allowed BC Hydro to defer specified costs to the Inflationary Pressures Regulatory Account. On November 28, 2022, the BCUC issued Order No. G-341-22 as directed to authorize BC Hydro to establish the Inflationary Pressures Regulatory Account and transfer $74 million from the Trade Income Deferral Account to the Inflationary Pressure Regulatory Account. In response to the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC issued Order No. G-76-25, as directed by the Government of BC in Direction No. 9, BC Hydro to recover the forecast balance, including forecast interest over the fiscal 2026 to fiscal 2027 test period.

Demand-Side Management

Demand-Side Management expenditures include materials, direct labour and applicable portions of support costs, equipment costs, and incentives, which are not eligible for capitalization. Costs relating to identifiable tangible assets that meet the capitalization criteria are recorded as property, plant and equipment. In March 2017, the Province issued Orders in Council No. 100 and No. 101, which enable BC Hydro to pursue cost-effective electrification and allows for costs related to undertakings pursuant to Order in Council No. 101 to be deferred to the Demand-Side Management Regulatory Account. Annual additions to the Demand-Side Management Regulatory Account are amortized on a straight-line basis over the anticipated 15 year benefit period.

First Nations Provisions & Costs

The First Nations Provisions Regulatory Account includes the present value of future payments and the First Nations Costs Regulatory Account includes the payments related to agreements reached with various First Nations groups. These agreements address settlements related to the construction and operation of the Company's existing facilities and provide compensation for associated impacts. Actual lump sum and annual settlement costs paid pursuant to these settlements are transferred from the First Nations Provisions Regulatory Account to the First Nations Costs Regulatory Account. In addition, annual negotiation costs are deferred to the First Nations Costs Regulatory Account.

Forecast lump sum settlement payments are amortized over 10 years starting in the year of payment, forecast annual settlement payments are amortized in the year of payment, and actual annual negotiation costs are recovered from the First Nations Costs Regulatory Account in the year incurred. Variances between forecast and actual lump sum and annual settlement payments in the current test period are recovered over the following test period.

Non-Current Pension Costs

The Non-Current Pension Costs Regulatory Account captures variances between forecast and actual non-current service costs, such as net interest income or expense related to pension and other post-employment benefit plans. In addition, all re-measurements of the net defined benefit liability are deferred to this account. Amounts deferred during the current test period are amortized at the start of the following test period over the expected average remaining service life of the employee group (currently 13 years).

PEB Current Pension Costs

The Post-Employment Benefit (PEB) Current Pension Costs regulatory account captures variances between forecast and actual costs related to the operating cost portion of post-employment benefits current pension costs. Variances deferred during the current test period are recovered over the following test period.

Site C

The Site C Regulatory Account captures Site C Project costs that are not eligible for capitalization. In its

Order G-91-23 on the *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application*, the BCUC approved BC Hydro's request to begin amortizing the balance of the Site C Regulatory Account commencing in fiscal 2025 over the forecast weighted average expected useful life of the Site C assets, originally estimated at 84 years in the *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application* and updated to 86 years for the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*.

Contributions in Aid (CIA) of Construction Amortization

This account captures the difference in amortization between the 45 year amortization period the Company uses for financial reporting and the 25 year amortization period determined by the BCUC for revenue requirement applications.

Environmental Provisions & Costs

A liability provision and offsetting regulatory asset has been established for environmental compliance and remediation arising from the costs that will likely be incurred to comply with the Federal Polychlorinated Biphenyl (PCB) Regulations enacted under the *Canadian Environmental Protection Act* and the Asbestos requirements of the Occupational Health and Safety Regulations under the jurisdiction of WorkSafe BC.

Actual expenditures related to environmental regulatory provisions are transferred to the environmental cost regulatory accounts. Forecast environmental and remediation costs are amortized from the accounts each year. Variances between forecast and actual environmental and remediation expenditures in the current test period are recovered over the following test period.

Smart Metering & Infrastructure

Net operating costs incurred with respect to the Smart Metering & Infrastructure program were deferred through the end of fiscal 2016 when the project was completed. Costs relating to identifiable tangible and intangible assets that meet the capitalization criteria were recorded as property, plant and equipment or intangible assets, respectively. The balance in the regulatory account at the end of fiscal 2016 is being amortized over a period of 13 years, reflecting the remaining period of the overall amortization period of 15 years, which is based on the average life of Smart Metering & Infrastructure assets.

IFRS Pension

Unamortized experience gains and losses on the pension and other post-employment benefit plans recognized at the time of transition to IFRS as part of the Prescribed Standards (the previous accounting standards applicable to BC Hydro that were effective April 1, 2012 to March 31, 2018) were deferred to this regulatory account to allow for recovery in future rates. The account balance is amortized/recovered over 20 years on a straight-line basis beginning in fiscal 2013.

IFRS Property, Plant & Equipment

This account includes the fiscal 2012 incremental costs impacts due to the application of the accounting principles of IFRS to Property, Plant & Equipment to the comparative fiscal year for the adoption of IFRS as part of the Prescribed Standards (the previous accounting standards applicable to BC Hydro that were effective April 1, 2012 to March 31, 2018). In addition, the account includes an annual deferral of overhead costs, ineligible for capitalization under the accounting principles of IFRS that was being phased in over 10 years and the phase in was completed in fiscal 2021. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

Debt Management

This account captures gains and losses on financial contracts that economically hedge future long-term debt. The realized gains or losses are amortized over the remaining term of the associated long-term debt issuances, commencing in the test period following the test period in which the long-term debt associated with a particular hedge is issued.

Total Finance Charges

This account is intended to mitigate the impact of certain variances that arise between the forecast finance costs in a revenue requirements application and actual finance charges incurred. Variances deferred during the current test period are recovered over the following test period.

Cloud Costs

This account is intended to capture actual cloud arrangement implementation costs that would have been capitalized for each project, had the cloud arrangement been eligible for capitalization as an intangible asset. The forecast balance in the account attributable to each forecast completed cloud arrangement is recovered over the expected term of each cloud arrangement.

Project Write-off Costs

This account is intended to capture actual project write offs in each fiscal year for which BC Hydro believes future recovery from ratepayers is appropriate. Write-off costs deferred in respect to completed fiscal years during a test period are recovered over the following test period.

Site C Variance Costs

This account is intended to capture specific variances related to amortization and finance charges on Site C assets in service, commencing fiscal 2023. The recovery period for this account will be determined by the BCUC as part of a future regulatory proceeding.

Rate Smoothing

In February 2024, the BCUC approved a Rate Smoothing regulatory account to defer an amount that would have otherwise been refunded to customers through the Trade Income Rate Rider on their bills in fiscal 2025, so that the balance could be used to lower rates in future periods. In March 2025, the BCUC issued Order No. G-76-25, as directed by the Government of BC in Direction No. 9, that the forecast balance in the Rate Smoothing Regulatory Account be refunded, as specified, in fiscal 2026 and fiscal 2027.

Electric Vehicle Rebate

This account is intended to capture revenue from specified low carbon fuel credits, costs of issuing electric vehicle rebates and forecast variances in program expenditures on administration and marketing. Recovery of administration and marketing costs were approved to be recovered over the following test period in the BCUC order on BC Hydro’s Application for Approval of the Electric Vehicle Rebate regulatory account. Revenue from specified low carbon fuel credits and costs of issuing electric vehicle rebates were expected to self-clear over time. However, the Province has cancelled the Electric Vehicle Rebate program; therefore, a refund mechanism will be required for the remaining specified low carbon fuel credits in excess of electric vehicle rebate costs. BC Hydro will file a request in its next revenue requirements application so the credit balance can be refunded in the test period commencing in fiscal 2028.

Other Regulatory Accounts

Other regulatory asset and liability accounts with individual balances less than $50 million include the following: Foreign Exchange Gains and Losses, Amortization of Capital Additions, Real Property Sales, Customer Crisis Fund, Electric Vehicle Public Charging, Mining Customer Payment Plan, Cloud Usage Fees, Mandatory Reliability Standards Costs, Load Attraction Costs, Routine Trouble and Storm Restoration Costs, Dismantling Cost, Electrification Customer Connection Costs, Insurance Costs, Regulatory Fees, Remote Community Electrification Repayment, and Net Salvage.

Note 17: Accounts Payable and Accrued Liabilities

(in millions)		**March 31, 2026**		March 31, 2025
Accounts payable	**$**	**649**	$	566
Accrued liabilities		**1,332**		1,174
Current portion of lease liabilities (Note 20)		**90**		78
Current portion of other long-term liabilities (Note 25)		**161**		149
Other		**64**		60
	$	**2,296**	$	2,027

Note 18: Debt

The Company's debt primarily comprises bonds and revolving borrowings obtained under an agreement with the Province.

Short-term Borrowings

Short-term borrowings include amounts under a commercial paper borrowing program with the Province which is limited to $5.50 billion and a non-revolving credit facility limited to $140 million. At March 31, 2026, the outstanding amount under the commercial paper borrowing program was $4.44 billion (March 31, 2025 - $3.25 billion) and the outstanding amount under the non-revolving credit facility was $59 million (March 31, 2025 - $nil).

Long-term Debt

For the year ended March 31, 2026, the Company issued bonds for net proceeds of $2.92 billion (2025 - $4.22 billion) and a par value of $2.98 billion (2025 - $4.20 billion), a weighted average effective interest rate of 4.4 per cent (2025 - 4.2 per cent) and a weighted average term to maturity of 25 years (2025 - 24 years).

For the year ended March 31, 2026, the Company redeemed bonds at maturity with a par value of $2.02 billion (2025 - $10 million).

Debt, expressed in Canadian dollars, is summarized in the following table by year of maturity:

(in millions)	**March 31, 2026**					March 31, 2025				
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:										
2026	**$ -**	**$ -**	**$ -**	**$ -**	**-**	$ 900	$ 719	$ 410	$ 2,029	3.7
2027	**850**	**-**	**-**	**850**	**2.4**	850	-	-	850	2.4
2028	**1,000**	**-**	**-**	**1,000**	**2.8**	1,000	-	-	1,000	2.8
2029	**1,500**	**-**	**-**	**1,500**	**2.8**	1,500	-	-	1,500	2.8
2030	**500**	**-**	**-**	**500**	**5.0**	500	-	-	500	5.0
2031	**1,725**	**-**	**-**	**1,725**	**1.6**	-	-	-	-	-
1-5 years	**5,575**	**-**	**-**	**5,575**	**2.5**	4,750	719	410	5,879	3.2
6-10 years	**5,325**	**-**	**223**	**5,548**	**3.8**	6,275	-	216	6,491	3.2
11-15 years	**1,250**	**417**	**-**	**1,667**	**5.5**	-	432	-	432	7.4
16-20 years	**4,588**	**-**	**-**	**4,588**	**3.9**	5,838	-	-	5,838	4.1
21-25 years	**5,545**	**-**	**-**	**5,545**	**2.9**	3,695	-	-	3,695	3.2
26-30 years	**7,220**	**-**	**-**	**7,220**	**4.2**	5,710	-	-	5,710	3.4
Over 30 years	**50**	**-**	**-**	**50**	**3.4**	1,210	-	-	1,210	4.1
Bonds	**$ 29,553**	**$ 417**	**$ 223**	**$ 30,193**	**3.6**	$ 27,478	$ 1,151	$ 626	$ 29,255	3.5
Short-term borrowings	**3,904**	**593**	**-**	**4,497**	**2.4**	2,550	704	-	3,254	2.9
	$ 33,457	**$ 1,010**	**$ 223**	**$ 34,690**		$ 30,028	$ 1,855	$ 626	$ 32,509	
Adjustments to carrying value resulting from discontinued hedging activities	**5**	**14**	**-**	**19**		6	15	-	21	
Unamortized premium, discount, and issue costs	**(122)**	**(4)**	**(1)**	**(127)**		(61)	(5)	-	(66)	
	$ 33,340	**$ 1,020**	**$ 222**	**$ 34,582**		$ 29,973	$ 1,865	$ 626	$ 32,464	
Less: Current portion	**(4,754)**	**(593)**	**-**	**(5,347)**		(3,451)	(1,423)	(410)	(5,284)	
Non-current long-term debt	**$ 28,586**	**$ 427**	**$ 222**	**$ 29,235**		$ 26,522	$ 442	$ 216	$ 27,180	

[1]The weighted average interest rate represents the effective rate of interest on fixed-rate bonds.

The following foreign currency contracts were in place at March 31, 2026 in a net asset position of $21 million (2025 – net asset of $88 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**March 31, 2026**	March 31, 2025
Cross-Currency Swaps		
Euro dollar (€) to Canadian dollar - notional amount[1]	**€ 138**	€ 402
Euro dollar to Canadian dollar - weighted average contract rate	**1.44**	1.47
Weighted remaining term	**6 years**	3 years
Foreign Currency Forwards		
United States dollar (US$) to Canadian dollar - notional amount[1]	**US$ 659**	US$ 1,065
United States dollar to Canadian dollar - weighted average contract rate	**1.33**	1.32
Weighted remaining term	**3 years**	3 years

[1]Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

The following forward swap contracts were in place at March 31, 2026 with a net asset position of $166 million (2025 - net liability of $58 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $3.58 billion (2025 - $3.48 billion) of planned 10 and 30 year debt (2025 - 10 and 30 year debt) to be issued on dates ranging from June 2026 to October 2029 (2025 - July 2025 to October 2028).

(in millions)	**March 31, 2026**	March 31, 2025
Forward Swaps		
Canadian dollar - notional amount[1]	**$ 3,575**	$ 3,475
Weighted forecast borrowing yields	**4.17%**	3.89%
Weighted remaining term	**1 year**	1 years

[1]Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

For more information about the Company’s exposure to interest rate, foreign currency and liquidity risk, see Note 24.

Note 19: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

(in millions)	**2026**	2025
Restricted Cash	**$ (19)**	$ 10
Accounts receivable, accrued revenue, prepaid expenses and other non-current assets	**(201)**	128
Inventories	**47**	(29)
Accounts payable, accrued liabilities, and other non-current liabilities	**219**	(267)
Unearned revenues, customer credits and contributions in aid	**184**	(16)
Post-employment benefits	**(2)**	1
	$ 228	$ (173)

Non-Cash Investing Transactions:

(in millions)	**2026**	2025
Contributions in kind received for property, plant and equipment	**$ 55**	$ 97

Reconciliation for liabilities:

(in millions)	**Balance, April 1, 2025**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Proceeds (Payments)**	**Balance March 31, 2026**
Long-term debt and short-term borrowings:							
Long-term debt	$ 29,210	$ 2,923	$ (2,023)	$ (15)	$ (10)	$ -	$ 30,085
Short-term borrowings	3,254	9,980	(8,713)	(21)	(3)	-	4,497
Total long-term debt and short-term borrowings (Note 18)	32,464	12,903	(10,736)	(36)	(13)	-	34,582
Lease liability (Note 20)	1,348	-	-	-	87	(133)	1,302
Vendor financing liability	248	-	-	-	23	(42)	229
Debt-related derivative net asset	(30)	-	-	-	(311)	154	(187)
	$ 34,030	$ 12,903	$ (10,736)	$ (36)	$ (214)	$ (21)	$ 35,926

[1] Other includes new lease liability, fair value adjustments to the debt-related derivative liability, interest, and other non-cash items.

(in millions)	Balance, April 1, 2024	Issued	Redemptions	Foreign exchange movement	Other[1]	Proceeds (Payments)	Balance March 31, 2025
Long-term debt and short-term borrowings:							
Long-term debt	$ 24,907	$ 4,217	$ (10)	$ 107	$ (11)	$ -	$ 29,210
Short-term borrowings	4,730	8,414	(9,919)	66	(37)	-	3,254
Total long-term debt and short-term borrowings (Note 18)	29,637	12,631	(9,929)	173	(48)	-	32,464
Lease liability (Note 20)	1,405	-	-	-	62	(119)	1,348
Vendor financing liability	273	-	-	-	16	(41)	248
Debt-related derivative net asset	(191)	-	-	-	19	142	(30)
	$ 31,124	$ 12,631	$ (9,929)	$ 173	$ 49	$ (18)	$ 34,030

[1] Other includes new lease liability, fair value adjustments to the debt-related derivative liability, interest, and other non-cash items.

Note 20: Lease Liabilities

Lease costs

(in millions)	**2026**	2025
Interest on lease liabilities	**$ 43**	$ 44
Variable lease payments (recoveries) not included in the measurement of lease liabilities	**3**	(14)
Expenses relating to short-term leases and leases of low-value assets	**38**	26
	$ 84	$ 56

Amounts recognized in the statement of cash flows

(in millions)	**2026**	2025
Total cash outflow for leases	**$ 174**	$ 131

Maturity analysis

(in millions)	**March 31, 2026**	March 31, 2025
Maturity analysis - contractual undiscounted cash flows		
Less than 1 year	**$ 130**	$ 122
1 to 5 years	**391**	410
More than 5 years	**1,228**	1,337
Total Undiscounted Lease Liabilities	**$ 1,749**	$ 1,869

(in millions)		**March 31, 2026**		March 31, 2025
Current	**$**	**90**	$	78
Non-current		**1,212**		1,270
Total Lease Liabilities	**$**	**1,302**	$	1,348

Long-term energy purchase agreements

The Company has entered into some long-term energy purchase agreements that are considered to be a lease. The long-term energy purchase agreements have terms ranging from 4.5 years to 30 years with no option to renew. The lease payments are adjusted annually for changes in the consumer price index, and these amounts are included in the measurement of the lease liability. The variable lease payments (recoveries) for these long-term energy purchase agreement leases for the year ended March 31, 2026 were $2 million (2025 - $15 million recoveries). The variable rent recoveries for the year ended March 31, 2025 was mainly due to waivers of payments associated with generating unit outages. See note 26 for long-term energy purchase agreements with related parties.

Property leases

The Company leases land and building for its office space and operation use. The property leases typically run for a period of 2 years to 99 years. Some leases include an option to renew the leases for an additional period ranging from 1 year to 10 years.

Some leases require the Company to make payments that relate to the property taxes, insurance payments and operating costs; these amounts are generally determined annually. These variable lease payments for the year ended March 31, 2026 were $1 million (2025 - $1 million).

Other leases

The Company leases telecom equipment and the lease liability for each item will be settled in two equal installments that are due at the first and second year anniversaries after each item becomes operational. In addition, the company has commitments to pay $39 million over the next five years associated with lease assets that have not yet commenced.

The Company also leases vehicles, office equipment and other equipment. These vehicle leases are short-term, and office and other equipment leases are short-term and/or leases of low value items. The Company has elected not to recognize right-of-use assets and lease liabilities as a result of the practical expedients used as noted in note 3(r).

Note 21: Unearned Revenues and Contributions in Aid

(in millions)		**March 31, 2026**		March 31, 2025
Unearned revenues	**$**	**350**	$	358
Contributions in aid		**3,026**		2,834
		3,376		3,192
Less: Current portion, unearned revenues		**(59)**		(53)
Less: Current portion, contributions in aid		**(75)**		(70)
	$	**3,242**	$	3,069

Note 22: Capital Management

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual payment to the Province (see below). Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive loss, and contributed surplus. The Company monitors its capital structure on the basis of its debt to equity ratio.

During the year, there were no changes in the approach to capital management.

The debt to equity ratio at March 31, 2026, and March 31, 2025 was as follows:

(in millions)		**March 31, 2026**		March 31, 2025
Total debt	**$**	**34,582**	$	32,464
Less: Sinking funds		**(56)**		(279)
Less: Cash and cash equivalents		**(122)**		(136)
Net Debt	**$**	**34,404**	$	32,049
Retained earnings	**$**	**8,979**	$	8,261
Contributed surplus		**60**		60
Accumulated other comprehensive loss		**(49)**		(67)
Total Equity	**$**	**8,990**	$	8,254
Net Debt to Equity Ratio		**79 : 21**		**80 : 20**

Dividend Payment to the Province

In accordance with Order in Council No. 095/2014 from the Province, the payment to the Province will remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

As BC Hydro has not achieved a debt to equity ratio of 60:40 there was no payment for the year ended March 31, 2026 and March 31, 2025.

During the year ended March 31, 2026, the Company contributed $3 million (2025 - $3 million) funding to the Province to support incremental workload associated with environmental assessment and permitting resources.

Note 23: Post-Employment Benefits

The Company provides a defined benefit statutory pension plan (registered under the British Columbia *Pension Benefits Standards Act*) to substantially all employees, as well as supplemental arrangements which provide pension benefits in excess of statutory limits. Pension benefits are based on years of membership service and highest five-year average pensionable earnings. The plan also provides pensioners a conditional indexing fund. Employees and the Company make equal basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings in accordance with the plan provisions and as recommended by the independent actuary. The Company may be required to contribute additional amounts as recommended by the independent actuary. The Company is responsible for ensuring that the defined benefit statutory pension plan has sufficient assets to pay the pension benefits. The supplemental arrangements are not funded. The defined benefit pension plans are administered under a defined governance structure. The pension arrangements including investment, plan benefits and funding decisions are administered by the Company's Pension Management Committee with oversight resting with the Board of Directors. Significant changes to the plans, investment policies, and funding policies require the approval of the Board of Directors. The most recent actuarial funding valuation for the statutory pension plan was performed as at December 31, 2023. The valuation has been extrapolated to March 31, 2026 in accordance with IAS 19 and incorporated in these financial statements. The next valuation for funding purposes is required no later than December 31, 2026.

The Company also provides post-employment benefits other than pensions including limited medical, extended health, dental and life insurance coverage for retirees who have at least 10 years of service and qualify to receive pension benefits. Certain benefits, including the short-term continuation of health care and life insurance, are provided to terminated employees or to survivors on the death of an employee. These post-employment benefits other than pensions are not funded. Post-employment benefits include the pay out of benefits that vest or accumulate, such as banked vacation.

By their design, defined benefit pension plans and other post-employment benefit plans expose the Company to various risks such as investment performance, reductions in discount rates used to value the obligations, increased longevity of plan members and future inflation levels impacting future salary increases and indexing, as well as future increases in healthcare costs.

Information about the pension benefit plans and post-employment benefits other than pensions is as follows:

(a) The expense for the Company's benefit plans for the years ended March 31, 2026 and 2025 is recognized in the following line items in the statement of comprehensive income prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions:

(in millions)	Pension Benefit Plans **2026**	2025	Other Benefit Plans **2026**	2025	Total **2026**	2025
Current service costs charged to personnel expense - operating expenses	**$ 132**	$ 112	**$ 5**	$ 5	**$ 137**	$ 117
Net interest costs charged to finance costs	**33**	26	**8**	9	**41**	35
Total post-employment benefit plan expense	**$ 165**	$ 138	**$ 13**	$ 14	**$ 178**	$ 152

Actuarial gain recognized in other comprehensive income was $442 million (2025 – loss of $94 million).

(b) Information about the Company's defined benefit plans, in aggregate, is as follows:

(in millions)	Pension Benefits Plans **March 31, 2026**	March 31, 2025	Other Benefits Plans **March 31, 2026**	March 31, 2025	Total **March 31, 2026**	March 31, 2025
Defined benefit obligation of funded plan	**$ (5,807)**	$ (5,827)	**$ -**	$ -	**$ (5,807)**	$ (5,827)
Defined benefit obligation of unfunded plans	**(174)**	(182)	**(179)**	(177)	**(353)**	(359)
Fair value of plan assets	**5,643**	5,324	**-**	-	**5,643**	5,324
Plan deficit	**$ (338)**	$ (685)	**$ (179)**	$ (177)	**$ (517)**	$ (862)
Represented by:						
Accrued benefit plan liability	**$ (338)**	$ (685)	**$ (179)**	$ (177)	**$ (517)**	$ (862)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2026 and fiscal 2025 in accordance with IFRIC 14*, The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction*.

(c) Movement of defined benefit obligations and defined benefit plan assets during the year:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**March 31, 2026**	March 31, 2025	**March 31, 2026**	March 31, 2025
Defined benefit obligation				
Opening defined benefit obligation	**$ 6,009**	$ 5,460	**$ 177**	$ 176
Current service cost	**132**	112	**5**	5
Interest cost on benefit obligations	**318**	321	**8**	9
Benefits paid[1]	**(232)**	(224)	**(6)**	(6)
Employee contributions	**63**	62	**-**	-
Actuarial losses (gains)[2]	**(309)**	278	**(5)**	(7)
Defined benefit obligation, end of year	**5,981**	6,009	**179**	177
Fair value of plan assets				
Opening fair value	**5,324**	4,944	**n/a**	n/a
Interest income on plan assets[3]	**285**	295	**n/a**	n/a
Employer contributions	**64**	63	**n/a**	n/a
Employee contributions	**63**	62	**n/a**	n/a
Benefits paid[1]	**(221)**	(217)	**n/a**	n/a
Actuarial gains[2,3]	**128**	177	**n/a**	n/a
Fair value of plan assets, end of year	**5,643**	5,324	**-**	-
Accrued benefit liability	**$ (338)**	$ (685)	**$ (179)**	$ (177)

[1] Benefits paid under Pension Benefit Plans include $12 million (2025 - $14 million) of settlement payments.

[2] Actuarial gains/losses are included in the Non-Current Pension Costs Regulatory Account and for fiscal 2026 are comprised of:
- $128 million of actuarial gains on return on plan assets (2025 - $177 million actuarial gains) due to higher actual return; and
- $314 million of actuarial gains (2025 - $271 million actuarial losses) on the benefit obligations mainly due to an increase in the discount rate.

[3] Actual income on defined benefit plan assets for the year ended March 31, 2026 was $413 million (2025 - $472 million).

(d) The significant assumptions adopted in measuring the Company's accrued benefit obligations as at each March 31 year end are as follows:

	Pension Benefit Plans		**Other Benefit Plans**	
	March 31, 2026	March 31, 2025	**March 31, 2026**	March 31, 2025
Discount rate				
Benefit cost	**4.64%**	4.89%	**4.64%**	4.87%
Accrued benefit obligation	**5.11%**	4.64%	**4.95%**	4.64%
Rate of return on plan assets	**4.64%**	4.89%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.50%**	3.50%	**3.50%**	3.50%
Accrued benefit obligation	**3.50%**	3.50%	**3.50%**	3.50%
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**3.44%**	3.43%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**3.44%**	3.43%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**n/a**	n/a

The valuation cost method for the accrued benefit obligation is the projected unit credit method pro-rated on service.

(e) Defined benefit statutory pension plan assets are invested prudently in order to meet the Company's pension obligations. The pension plan's investment strategy is to hold a diversified mix of investments by asset class and geographic location in order to reduce investment-specific risk to the funded status while maximizing the expected returns to meet pension obligations. Investment of the plan's assets follows an asset/liability framework as investment is conducted with consideration of the pension obligation's sensitivity to interest rates which is a key risk factor impacting the obligation's value.

In developing the pension plan's asset mix, the Company includes, but is not limited to, the following factors:

- the nature of the underlying benefit obligations, including the duration and term profile of the liabilities;
- the member demographics, including expectations for normal retirements, terminations, and deaths;
- the financial position of the pension plan;
- the diversification benefits obtained by the inclusion of multiple asset classes; and
- expected asset returns, including asset and liability correlations, along with liquidity requirements of the plan.

To implement the asset mix policy, the Company may invest in fixed interest investments (such as debt instruments), equity securities, and alternative investments. The Company's defined benefit statutory pension plan assets are primarily comprised of debt and equity securities and alternative investments.

The publicly traded equity securities are unadjusted quoted market prices in an active market (Level 1) and the publicly traded fixed interest investments generally have quoted market prices or observable market inputs for similar assets in an active market (Level 2). Alternative investments include private fund investments including infrastructure, renewable resources, real estate, mortgages and private equity and debt, all of which usually do not have quoted market prices available (Level 3). These fund assets are valued by external managers and independent valuators using accepted industry valuation methods and models.

(f) Asset allocation of the defined benefit statutory pension plan as at the measurement date:

	Long Term Strategic Target Allocation	Target Range Min	Target Range Max	March 31, 2026	March 31, 2025
Fixed interest investments	20%	15%	35%	**21%**	21%
Public equities	40%	30%	50%	**41%**	40%
Real estate	15%	10%	20%[1]	**13%**	14%
Private equities	15%	10%	20%[1]	**15%**	15%
Infrastructure and renewable resources	10%	5%	15%[1]	**10%**	10%

[1]The total of these three cannot exeed 50%.

Plan assets are re-balanced within ranges around target applications. An updated asset allocation was approved in fiscal 2026 and will be implemented starting in fiscal 2027. The Company's expected return on plan assets is determined as the discount rate in accordance with IAS19.

(g) Other information about the Company's benefit plans is as follows:

The Company's contribution to be paid to its funded defined benefit statutory pension plan in fiscal 2027 is expected to amount to $68 million. The expected benefit payments to be paid in fiscal 2027 in respect to the unfunded defined benefit plans are $14 million.

The following table presents the maturity profile of the Company's defined benefit statutory pension plan obligation:

(*in millions, except weighted average duration and plan participants*)

Number of plan participants as at March 31, 2026		17,271
Actual benefit payments 2026	$	217
Benefits expected to be paid 2027	$	238
Benefits expected to be paid 2028	$	243
Benefits expected to be paid 2029	$	249
Benefits expected to be paid 2030	$	255
Benefits expected to be paid 2031	$	262
Benefits expected to be paid 2032-2035	$	1,107
Weighted average duration of defined benefit payments		13.4 years

Assumptions adopted can have a significant effect on the value of the obligations for defined benefit pension and other post-employment benefit plans and are based on historical experience and market inputs. The increase (decrease) in obligation in the following table has been determined for key assumptions assuming all other assumptions are held constant. In practice, this is unlikely to occur, as changes in some of the assumptions may be correlated. The table below presents the sensitivity analysis of key assumptions for 2026.

The impact on the defined benefit obligation for the Pension Benefit Plans of changing certain of the major assumptions is as follows:

		2026	
(in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	-571	-32
Discount rate	1% decrease	+719	+43
Longevity	1 year increase	+116	+3
Longevity	1 year decrease	-118	-3
Compensation	1% increase	+183	+20
Compensation	1% decrease	-159	-17

Note 24: Financial Instruments

Financial Risk Management Overview

The Company is exposed to a number of financial risks in the normal course of its business operations, including market risks resulting from fluctuations in commodity prices, interest rates and foreign currency exchange rates, as well as credit risks and liquidity risks. The nature of the financial risks and the Company's strategy for managing these risks has not changed significantly from the prior year. Risk management strategies and policies are employed to ensure that any exposures to these risks are in compliance with the Company's business objectives and risk tolerance levels set out in the Company's Treasury Risk Management Policy and Liability Risk Management Annual Strategic Plan. Responsibility for the oversight of risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under IFRS 7, *Financial Instruments: Disclosures.* However, for a complete understanding of the nature and extent of financial risks the Company is exposed to, this note should be read in conjunction with the Company's discussion of Risk Management found in the Management's Discussion and Analysis section of the 2025/26 Annual Service Plan Report.

(a) Credit Risk

Credit risk refers to the risk that one party to a financial instrument will cause a financial loss for a counterparty by failing to discharge an obligation. The Company is exposed to credit risk related to cash and cash equivalents, restricted cash, accounts receivable, non-current receivables, sinking fund investments, and derivative instruments.

The Company manages financial institution credit risk through a Board-approved Treasury Risk Management Policy. Exposures to credit risks are monitored on a regular basis. Large customers are assessed for credit quality by taking into account external credit ratings, where available, an analysis of financial position and liquidity, past experience and other factors. The Company assigns credit limits for counterparties based on evaluations of their financial condition, net worth, credit ratings, and other credit criteria. For some customers, security over accounts receivable may be obtained in the form of a security deposit.

Maximum credit risk with respect to financial assets is limited to the carrying amount presented on the consolidated statement of financial position.

(b) Liquidity Risk

Liquidity risk refers to the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages liquidity risk by forecasting cash flows to identify financing requirements and by maintaining a commercial paper borrowing program under an agreement with the Province (see Note 18). The Company's debt primarily comprises bonds and revolving borrowings obtained under an agreement with the Province. Cash from operations reduces the Company's liquidity risk. The Company does not believe that it will encounter difficulty in meeting its obligations associated with financial liabilities.

(c) Market Risks

Market risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk, and other price risk, such as changes in commodity prices. The Company monitors its exposure to market fluctuations and may use derivative contracts to manage these risks, as it considers appropriate.

(i) Currency Risk

Currency risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The Company's currency risk is primarily with the U.S. dollar.

The majority of the Company's currency risk arises from long-term debt in the form of U.S. dollar denominated bonds. Energy commodity prices are also subject to currency risk as they are primarily denominated in U.S. dollars. As a result, the Company's trade revenues and purchases of energy commodities, such as electricity and natural gas, and associated accounts receivable and accounts payable, are affected by the Canadian/U.S. dollar exchange rate. In addition, all commodity derivatives and contracts priced in U.S. dollars are also affected by the Canadian/U.S. dollar exchange rate.

The Company actively manages its currency risk through its Treasury Risk Management Policy. The Company uses cross-currency swaps and forward foreign exchange purchase contracts to achieve and maintain foreign currency exposure targets.

(ii) Interest Rate Risk

Interest rate risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to changes in interest rates primarily through its variable rate debt and the active management of its debt portfolio including its related sinking fund assets and temporary investments. The Company actively manages its interest rate risk through its Treasury Risk Management Policy. The Company uses interest rate swaps and bond locks to lock in interest rates on future debt issues to protect against rising interest rates.

(iii) Commodity Price Risk

Commodity price risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company has exposure to movements in prices for commodities including electricity, natural gas, environmental products and other associated products. Prices for electricity and natural gas fluctuate in response to changes in supply and demand, market uncertainty, and other factors beyond the Company's control.

The management of commodity price risk is governed by risk management policies with oversight from either the BC Hydro or subsidiary Board of Directors. Risk management strategies, policies and limits are designed to ensure the Company's risks and related exposures are aligned with the Company's business objectives and risk tolerance. Risk management policies and procedures are reviewed regularly to reflect changes in market conditions and the Company's activities.

Categories of Financial Instruments

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2026, and March 31, 2025. It does not include fair value information for non-derivative financial instruments not measured at fair value if the carrying amount is a reasonable approximation of fair value which include cash and cash equivalents, restricted cash, accounts receivable and accrued revenue, accounts payable, accrued liabilities and short-term borrowings. Their carrying amount is a reasonable approximation of fair value due to the short duration of these financial instruments. When the carrying value differs from fair value, the fair values of the non-derivative financial instruments would be classified as Level 2 of the fair value hierarchy.

	March 31, 2026		March 31, 2025		**2026**	2025
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	**Interest Income (Expense) recognized in Finance Charges**	Interest Income (Expense) recognized in Finance Charges
Amortized Cost:						
Non-current receivables	**$ 104**	**$ 106**	$ 114	$ 117	**$ 6**	$ 5
Sinking funds (including current portion due in one year)	**56**	**57**	279	274	**5**	16
Long-term debt (including current portion due in one year)	**(30,085)**	**(27,766)**	(29,210)	(27,945)	**(1,088)**	(967)
First Nations liabilities (non-current portion)	**(447)**	**(448)**	(444)	(470)	**(20)**	(17)
Other liabilities (non-current portion)	**(418)**	**(406)**	(397)	(386)	**(16)**	(18)

Hedges

As permitted by the transitional provision for hedge accounting under IFRS 9, the Company has elected to continue with the hedging requirements of IAS 39, Financial Instruments: Recognition and Measurement (IAS 39) and not adopt the hedging requirements of IFRS 9.

The following foreign currency contracts under hedge accounting were in place at March 31, 2026 in a net asset position of $15 million (2025 - net asset of $67 million). Such contracts are used to hedge the principal on US$ denominated long-term debt and the principal and coupon payments on Euro€ denominated long-term debt for which hedge accounting has been applied. The hedging instruments are effective in offsetting changes in the cash flows of the hedged item attributed to the hedged risk. The main source of hedge ineffectiveness in these hedges is credit risk.

($ amounts in millions)		**March 31, 2026**		March 31, 2025
Cross- Currency Hedging Swap				
EURO € to CAD$ - notional amount[1]	**€**	**138**	€	402
EURO € to CAD$ - contract rate		**1.44**		1.47
Remaining term		**6 years**		3 years
Foreign Currency Hedging Forward				
US$ to CAD$ - notional amount[1]	**US$**	**230**	US$	573
US$ to CAD$ - contract rate		**1.23**		1.25
Remaining term		**10 years**		5 years

[1]Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

The fair value of derivative instruments designated and not designated as hedges, was as follows:

(in millions)		**March 31, 2026 Fair Value**		March 31, 2025 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:				
Foreign currency contract assets (cash flow hedges for US$ denominated long-term debt)	**$**	**11**	$	59
Foreign currency contract assets (cash flow hedges for EURO€ denominated long-term debt)		**4**		14
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)		**-**		(6)
		15		67
Non-Designated Derivative Instruments:				
Interest rate contract assets		**172**		41
Interest rate contract liabilities		**(6)**		(99)
Foreign currency contract assets		**6**		21
Commodity derivative assets		**237**		231
Commodity derivative liabilities		**(139)**		(171)
		270		23
Net assets	**$**	**285**	$	90

The carrying value of derivative instruments designated and not designated as hedges was the same as the fair value.

For designated cash flow hedges for the year ended March 31, 2026, there was a gain of $26 million (2025 - gain of $54 million). The effective portion was recognized in other comprehensive income. For the year ended March 31, 2026, $3 million (2025 – $88 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains (2025 - losses) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $3.58 billion (2025 - $3.48 billion), used to economically hedge the interest rates on future debt issuances, there was a $200 million increase (2025 - $105 million decrease) in the fair value of these contracts for the year ended March 31, 2026. For interest rate contracts associated with debt issued, there was a $100 million increase (2025 - $60 million decrease) in the fair value of contracts that settled during the year ended March 31, 2026. The net increase for the year ended March 31, 2026 of $300 million (2025 - $165 million decrease) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a net liability balance of $256 million as at March 31, 2026.

Foreign currency contracts associated with U.S. revolving borrowings not designated as hedges, for the year ended March 31, 2026, had a loss of $15 million (2025 – gain of $78 million) recognized in finance charges. These economic hedges offset $22 million of foreign exchange revaluation gains (2025 – loss of $67 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2026.

For commodity derivatives not designated as hedges, a net gain of $428 million (2025 – gain of $490 million) was recorded in trade revenue for the year ended March 31, 2026.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2026**		2025
Deferred inception gains, beginning of the year	**$**	**70**	$	31
New transactions		**5**		56
Amortization		**(27)**		(20)
Foreign currency translation (gain) loss		**(2)**		3
Deferred inception gains, end of the year	**$**	**46**	$	70

CREDIT RISK

Domestic Electricity Receivables

A customer application and a credit check are required prior to initiation of services. For customers with no BC Hydro credit history, the Company ensures accounts are secured either by a credit bureau check, a cash security deposit, or a credit reference letter.

The value of the current domestic and trade accounts receivable, by age and the related provision for doubtful accounts are presented in the following table:

Current Domestic and Trade Accounts Receivable Net of Allowance for Doubtful Accounts

(in millions)	**March 31, 2026**	March 31, 2025
Current	**$ 358**	$ 322
Past due (30-59 days)	**28**	31
Past due (60-89 days)	**8**	8
Past due (More than 90 days)	**9**	10
	403	371
Less: Allowance for doubtful accounts	**(6)**	(6)
	$ 397	$ 365

Financial Assets Arising from the Company's Trading Activities

The Company's management of credit risk generally includes evaluation of counterparty's credit quality, establishment of credit limits, and measurement, monitoring and mitigation of exposures. The Company assesses the creditworthiness of counterparties before entering into contractual obligations, and then reassesses changes on an ongoing basis. Credit risk is managed through securing, where appropriate, corporate guarantees, cash collateral, letters of credit, or third party credit insurance, and through the use of master netting agreements and margining provisions in contracts. Counterparty exposures are monitored on a daily basis against established credit limits. The Company's counterparties span a variety of industries. There is no significant industry concentration of credit risk.

The following table sets out the carrying amounts of recognized financial instruments presented in the consolidated statement of financial position on a gross basis that are subject to derivative master netting agreements or similar agreements:

(in millions)	Gross Derivative Instruments	Related Instruments Not Offset	Net Amount
As at March 31, 2026			
Derivative commodity assets	**$ 237**	**$ 1**	**$ 236**
Derivative commodity liabilities	**139**	**1**	**138**
As at March 31, 2025			
Derivative commodity assets	$ 231	$ 2	$ 229
Derivative commodity liabilities	171	2	169

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2026 of the Company's non-derivative financial liabilities and derivative financial liabilities, which are based on contractual undiscounted cash flows. Interest payments have been computed using contractual rates or, if floating, based on rates current at March 31, 2026. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2026 has been used.

(in millions)	**Fiscal 2027**	**Fiscal 2028**	**Fiscal 2029**	**Fiscal 2030**	**Fiscal 2031**	**Fiscal 2032** ***and thereafter***
Non-Derivative Financial Liabilities						
Total accounts payable and other payables (excluding interest accruals and current portion of lease obligations and First Nations liabilities)	$ (1,857)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	(6,437)	(2,050)	(2,537)	(1,479)	(2,672)	(37,860)
Lease obligations	(130)	(117)	(104)	(89)	(81)	(1,228)
Other long-term liabilities	(67)	(209)	(77)	(76)	(64)	(1,700)
Total Non-Derivative Financial Liabilities	(8,491)	(2,376)	(2,718)	(1,644)	(2,817)	(40,788)
Derivative Financial Liabilities						
Other forward foreign exchange contracts designated at fair value						
Cash outflow	(110)	-	-	-	-	-
Cash inflow	111	-	-	-	-	-
Interest rate swaps used for hedging	(4)	-	(1)	-	-	-
Total Derivative Financial Liabilities	(3)	-	(1)	-	-	-
Total Financial Liabilities	(8,494)	(2,376)	(2,719)	(1,644)	(2,817)	(40,788)
Derivative Financial Assets						
Cross currency swaps used for hedging						
Cash outflow	(5)	(5)	(5)	(5)	(5)	(207)
Cash inflow	2	2	2	2	2	226
Forward foreign exchange contracts used for hedging						
Cash outflow	-	-	-	-	-	(283)
Cash inflow	-	-	-	-	-	320
Other forward foreign exchange contracts designated at fair value						
Cash outflow	(479)	-	-	-	-	-
Cash inflow	486	-	-	-	-	-
Interest rate swaps used for hedging	65	63	47	5	-	-
Net commodity derivatives	76	25	16	14	10	16
Total Derivative Financial Assets	145	85	60	16	7	72
Net Financial Liabilities	**$ (8,349)**	**$ (2,291)**	**$ (2,659)**	**$ (1,628)**	**$ (2,810)**	**$ (40,716)**

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis

For changes in the U.S. dollar to Canadian dollar exchange rate, an increase (decrease) of $0.01 at March 31, 2026 would otherwise have a negative (positive) impact on net income before movement in regulatory balances of $4 million, but as a result of regulatory accounting, it would have no impact on net income or other comprehensive income as all gains and losses will be captured in the Total Finance Charges Regulatory Account or the Foreign Exchange Gains/Losses Regulatory Account. This analysis assumes that all other variables, in particular interest rates, remain constant.

This sensitivity analysis has been determined assuming that the change in foreign exchange rates had occurred at March 31, 2026 and been applied to each of the Company's exposures to currency risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in foreign exchange.

(b) Interest Rate Risk

Sensitivity Analysis

For variable rate non-derivative instruments, an increase (decrease) of 100-basis points in interest rates at March 31, 2026 would otherwise have a negative (positive) impact on net income before movement in regulatory balance of $44 million, but as a result of regulatory accounting, it would have no impact on net income or other comprehensive income as all gains and losses will be captured in the Total Finance Charges Regulatory Account. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

For the interest rate contracts, as rounded to the nearest $25 million, an increase and decrease of 100-basis points in interest rates at March 31, 2026 would otherwise have a positive impact of $425 million and a negative impact of $525 million, respectively, on net income before movement in regulatory balances. As a result of regulatory accounting, it would have no impact on net income or other comprehensive income as all gains and losses will be captured in the Debt Management Regulatory Account.

This sensitivity analysis has been determined assuming that the change in interest rates had occurred at March 31, 2026 and been applied to each of the Company's exposure to interest rate risk for non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in interest rates over the period until the next consolidated statement of financial position date.

(c) Commodity Price Risk

Sensitivity Analysis

Commodity price risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in commodity prices.

The Company has exposure to movements in prices for commodities including electricity, natural gas, environmental products and associated derivative products. Prices for electricity and natural gas commodities fluctuate in response to changes in supply and demand, market uncertainty, and other factors beyond the Company's control.

The Company manages these exposures through its risk management policies, which limit components of and overall market risk exposures, pre-defined approved products and mandate regular reporting of exposures.

The Company's risk management policies for trading activities defines various limits and controls, including Value at Risk (VaR) limits, Mark-to-Market limits, and various transaction specific limits which are monitored on a daily basis. VaR is a statistical estimate of potential loss in value of the Company's positions due to adverse market movements with a specific level of confidence, over a specific time period. The Company calculates over a 10-day holding period, within a 95 per cent confidence level, resulting from normal market fluctuations.

The VaR model, an industry standard Monte Carlo model, uses historical information to determine potential future volatility and correlation, assuming that price movements in the recent past are indicative of near-term future price movements. It cannot forecast unusual events which can lead to extreme price movements. In addition, it is sometimes difficult to appropriately estimate VaR associated with illiquid or non-standard products. As a result, the Company uses additional measures to supplement the use of VaR to estimate price risk. These include the use of a Historic VaR methodology, stress tests and notional limits for illiquid or emerging products.

The VaR for commodity derivatives, calculated under this methodology, was approximately $9 million at March 31, 2026 (2025 - $22 million).

Fair Value Hierarchy

The following provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped based on the lowest level of input that is significant to that fair value measurement.

The inputs used in determining fair value are characterized by using a hierarchy that prioritizes inputs based on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 - values are quoted prices (unadjusted) in active markets for identical assets and liabilities.

- Level 2 - inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.

  The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which use contractual cash flows and market-related discount rates.

  Level 2 fair values for commodity derivatives are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e., derived from prices). Level 2 includes bilateral and over-the-counter contracts valued using interpolation from observable forward curves or broker quotes from active markets for similar instruments and other publicly available data, and options valued using industry-standard and accepted models incorporating only observable data inputs.

- Level 3 - inputs are those that are not based on observable market data. Level 3 fair values for commodity derivatives are determined using inputs that are based on significant unobservable inputs.

  Level 3 includes instruments valued using observable prices adjusted for unobservable basis differentials such as delivery location and product quality, instruments which are valued by extrapolation of observable market information into periods for which observable market information is not yet available, and instruments valued using internally developed or non-standard valuation models.

The following tables present the financial instruments measured at fair value for each hierarchy level as at March 31, 2026 and 2025:

As at March 31, 2026 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets (liabilities) carried at fair value:				
Short-term investments	$ 62	$ -	$ -	$ 62
Derivative financial instrument assets	39	200	191	430
Derivative financial instrument liabilities	(51)	(22)	(72)	(145)
	$ 50	$ 178	$ 119	$ 347

As at March 31, 2025 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets (liabilities) carried at fair value:				
Short-term investments	$ 78	$ -	$ -	$ 78
Derivative financial instrument assets	54	162	150	366
Derivative financial instrument liabilities	(41)	(146)	(89)	(276)
	$ 91	$ 16	$ 61	$ 168

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the year, there were no commodity transfers between Level 1 and Level 2 (2025 – no transfers).

The following table reconciles the changes in the balance of financial instruments carried at fair value on the consolidated statement of financial position, classified as Level 3, for the years ended March 31, 2026 and 2025:

(in millions)	
Balance as at April 1, 2025	**$ 61**
Realized and unrealized gains	483
Settlements	(424)
Foreign exchange	(1)
Balance as at March 31, 2026	**$ 119**

(in millions)		
Balance as at April 1, 2024	**$**	**(94)**
Realized and unrealized gains		377
Transfers		(10)
Settlements		(212)
Balance as at March 31, 2025	**$**	**61**

During the year, there were no commodity transfers between Level 2 and Level 3 (2025 - derivatives with a liability carrying amount of $10 million were transferred between Level 2 and Level 3).

During the year ended March 31, 2026, unrealized gains of $171 million (2025 – $89 million) were recognized on Level 3 derivative commodity financial instruments still on hand. These gains and losses were recognized in trade revenues.

Methodologies and procedures regarding commodity trading Level 3 fair value measurements are determined by the Company's risk management group. Level 3 fair values are calculated within the Company's risk management policies for trading activities based on underlying contractual data as well as observable and non-observable inputs. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by risk management and finance departments on a regular basis.

The key unobservable inputs in the valuation of certain Level 3 financial instruments includes components of forward commodity prices and delivery or receipt volumes. A sensitivity analysis was prepared using the Company's assessment of a reasonably possible change in various components of forward prices and volumes of 10 percent. Forward commodity prices used in determining Level 3 base fair value at March 31, 2026 range between $3-$194 per MwH and a 10 percent increase/decrease in certain components of these prices would decrease/increase fair value by $204 million. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $7 million.

Note 25: Other Non-Current Liabilities

(in millions)		**March 31, 2026**		March 31, 2025
Provisions				
Environmental liabilities	**$**	**217**	$	279
Decommissioning obligations		**138**		83
Other		**91**		77
		446		439
First Nations liabilities		**464**		462
Other contributions		**216**		213
Other liabilities		**516**		458
		1,642		1,572
Less: Current portion, included in accounts payable and accrued liabilities		**(161)**		(149)
	$	**1,481**	$	1,423

Changes in each class of provision during the financial year are set out below:

(in millions)	**Environmental**	**Decommissioning**	**Other**	**Total**
Balance at April 1, 2024	**$ 242**	**$ 62**	**$ 73**	**$ 377**
Made during the year	78	9	53	140
Used during the year	(53)	(3)	(48)	(104)
Changes in estimate	5	13	(2)	16
Changes due to currency translation	-	-	1	1
Accretion	7	2	-	9
Balance at March 31, 2025	**279**	**83**	**77**	**439**
Made during the year	4	3	20	27
Used during the year	(45)	(3)	(14)	(62)
Changes in estimate	(27)	52	8	33
Accretion	6	3	-	9
Balance at March 31, 2026	**$ 217**	**$ 138**	**$ 91**	**$ 446**

Environmental Liabilities

The Company has recorded a liability for the estimated future environmental expenditures related to present or past activities of the Company. The Company's recorded liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

At March 31, 2026, the undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2027 and 2086, is approximately $303 million and was determined based on current cost estimates. A range of discount rates between 2.6 per cent and 3.9 per cent were used to calculate the net present value of the obligations.

Decommissioning Obligations

The Company's decommissioning obligation provision consists of estimated removal and destruction costs associated with certain PCB and asbestos contaminated assets and certain submarine cables. The Company has determined its best estimate of the undiscounted amount of cash flows required to settle remediation obligations at $197 million (2025 - $130 million), which will be settled between fiscal 2027 and 2086. The undiscounted cash flows, discounted by a range of discount rates between 2.6 per cent and 3.9 per cent, were used to calculate the net present value of the obligations. The obligations are re-measured at each period end to reflect changes in estimated cash flows and discount rates.

First Nations Liabilities

The First Nations liabilities consist primarily of settlement costs related to agreements reached with various First Nations groups. First Nations liabilities are recorded as financial liabilities and are measured at fair value on initial recognition with future contractual cash flows being discounted at rates ranging from 4.4 per cent to 5.0 per cent. These liabilities are measured at amortized cost and not re-measured for changes in discount rates. The First Nations liabilities are non-interest bearing.

Other Contributions

Other contributions consist of contributions from vendors to aid in the construction of the transmission system. Contributions include payments received and also contributions to be received (refer to Note 14) and are being recognized as an offset to the applicable energy purchase costs over the life of the energy purchase agreement.

Other Liabilities

Other liabilities mainly include a contractual obligation associated with the construction of a capital project. This contractual obligation has an implicit interest rate of 7 per cent and a repayment term of 15 years commencing in fiscal 2019. This liability is measured at amortized cost and not re-measured for changes in discount rates. In addition, other liabilities also include long-term payables to other goods and service providers.

Note 26: Commitments and Contingencies

Energy Commitments

BC Hydro (excluding Powerex) has long-term energy and capacity purchase contracts to meet a portion of its expected future domestic electricity requirements. The expected obligations to purchase energy under these contracts have a total value of approximately $56.47 billion.

Included in the total value of the long-term energy purchase agreements is $1.65 billion accounted for as a lease liability under Note 20. The total BC Hydro combined payments are estimated to be approximately $1.54 billion for less than one year, $6.51 billion between one and five years, and $48.42 billion for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $4.15 billion extending to 2054 (including a purchase commitment with the Province of $1.82 billion). The total Powerex energy purchase commitments are estimated to be approximately $710 million for less than one year, $1.82 billion between one and five years, and $1.62 billion for more than five years.

Powerex has energy sales commitments of $4.89 billion extending to 2036 with estimated amounts of $879 million for less than one year, $2.21 billion between one and five years, and $1.80 billion for more than five years.

Lease and Service Agreements

The Company has entered into various agreements to lease facilities or assets or service agreements supporting operations. The agreements cover periods of up to 99 years, and the aggregate minimum payments are approximately $1.37 billion. Payments are $175 million for less than one year, $280 million between one and five years, and $918 million for more than five years. Included in the total value of the lease and service agreements is $94 million accounted for as a lease liability under Note 20.

Refer to Note 11 for commitments pertaining to major property, plant and equipment projects.

Contingencies and Guarantees

a) Facilities and Rights of Way: the Company is subject to existing and pending legal claims relating to alleged infringement and damages in the operation and use of facilities owned by the Company. These claims may be resolved unfavorably with respect to the Company and may have a significant adverse effect on the Company's financial position. For existing claims in respect of which settlement negotiations have advanced to the extent that potential settlement amounts can reasonably be predicted, management has recorded a liability for the potential costs of those settlements. For pending claims, management believes that there is a risk that any loss exposure that may ultimately be incurred may differ materially from management's current estimates. Management has not disclosed the ranges of expected outcomes due to the potentially adverse effect on the negotiation process for these claims.

b) Due to the size, complexity and nature of the Company's operations, various other legal matters are pending. In many cases, it is not possible at this time to predict with any certainty the outcome of such litigation. For existing claims in respect of legal matters which have advanced to the extent that potential settlement amounts can reasonably be predicted, management has recorded a liability for the potential costs of those settlements. Management believes that any other settlements related to these matters will not have a material effect on the Company's consolidated financial position or results of operations.

c) The Company and its subsidiaries have outstanding letters of credit totaling $97 million (2025 - $55 million). The total outstanding letter of credit also includes US $39 million (2025 - US $16 million) in foreign denominated letters of credit.

Note 27: Related Party Transactions

Subsidiaries

The principal subsidiaries of BC Hydro are Powerex and Powertech.

All companies are wholly owned and incorporated in Canada and all ownership is in the form of common shares. Operating out of Vancouver, BC, Canada, Powerex is a wholesale energy marketer, whose activities include trading electricity, environmental products, natural gas, and related financial and physical energy products in North America. Powertech offers services to solve technical problems with power equipment and systems in Canada and throughout the world.

All intercompany transactions and balances are eliminated upon consolidation.

Related Parties

As a Crown Corporation, the Company and the Province, including all ministries, crown corporations and agencies under the Province's control are considered related parties. All transactions between the Company and its related parties are considered to possess commercial substance and are consequently recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

The related party transactions are summarized below:

(in millions)	**March 31, 2026**	March 31, 2025
Consolidated Statement of Financial Position		
Prepaid expenses	**$ 108**	$ 94
Accounts receivable	**37**	6
Right-of-use assets	**1,080**	1,110
Accounts payable and accrued liabilities	**98**	101
Net Derivative assets (liabilities)	**145**	(46)
Lease liabilities	**1,254**	1,277

	2026	2025
Amounts incurred/accrued during the year include:		
Water rental fees	**336**	294
Energy Purchases	**238**	380
Grants and Taxes	**180**	177
Interest	**1,173**	1,119
Interest and foreign exchange derivatives settlement proceeds	**77**	(143)
Lease payments	**107**	74
Payment to the Province	**3**	3

In addition, the Company's debt is either held or guaranteed by the Province (see Note 18). Under an agreement with the Province, the Company indemnifies the Province for any credit losses incurred by the Province related to interest rate and foreign currency contracts entered into by the Province on the Company's behalf. As at March 31, 2026, the aggregate exposure under this indemnity totaled $194 million (2025 - $135 million). The Company has not experienced any losses to date under this indemnity. Future contractual arrangements with the Province pertaining to energy purchases are disclosed under Note 26.

BC Hydro is a Part 3 Fuel Supplier of British Columbia's low carbon fuel standard program and as a participant receives Low Carbon Fuel Credits from the Province, and these are sold to customers through a competitive process.

All other transactions with the Province, including all ministries, crown corporations and agencies under the Province's control occurred in the normal course of operations, and are not considered to be individually or collectively significant.

Key Management Personnel and Board Compensation

Key management personnel and board compensation includes compensation to the Company's executive management team and board of directors.

(in millions)	**2026**	2025
Short-term employee benefits	**$ 5**	$ 5
Post-employment benefits	**1**	1

Appendix D: Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2026**	2025	2024	2023[1]	2022[2]
Revenues					
Domestic	**$ 6,350**	$ 6,049	$ 5,504	$ 5,982	$ 5,619
Trade	**1,244**	1,429	1,627	2,496	1,972
	7,594	7,478	7,131	8,478	7,591
Expenses					
Energy costs	**2,749**	2,864	3,725	3,574	3,002
Other operating expenses[3]	**2,251**	2,009	1,675	1,538	1,427
Amortization and depreciation	**1,354**	1,200	1,071	1,052	1,079
Grants and taxes	**336**	326	316	296	286
Finance charges	**864**	1,094	516	496	521
	7,554	7,493	7,303	6,956	6,135
Net Income (Loss) Before Movement in Regulatory Balances	**40**	(15)	(172)	1,522	1,276
Net movement in regulatory balances	**681**	602	495	(1,162)	(608)
Net Income	**$ 721**	$ 587	$ 323	$ 360	$ 668
Property, Plant and Equipment, Right-of-Use Assets and Intangible Assets					
Property, Plant and Equipment	**$ 45,507**	$ 42,945	$ 40,108	$ 36,926	$ 34,038
Right-of-Use Assets	**1,132**	1,180	1,209	1,305	1,248
Intangible Assets	**666**	651	641	639	640
Net Book Value	**$ 47,305**	$ 44,776	$ 41,958	$ 38,870	$ 35,926
Property, Plant and Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,975**	$ 1,813	$ 1,477	$ 1,211	$ 1,119
Growth	**1,952**	2,202	2,786	2,708	2,356
Total Property, Plant and Equipment and Intangible Asset Expenditures	**$ 3,927**	$ 4,015	$ 4,263	$ 3,919	$ 3,475
Net Long-Term Debt [4]	**$ 34,404**	$ 32,049	$ 29,294	$ 26,630	$ 25,642
Retained Earnings	**$ 8,979**	$ 8,261	$ 7,677	$ 7,354	$ 6,994
Debt to Equity Ratio	**79 : 21**	80 : 20	79 : 21	78 : 22	78 : 22

1 In 2023/24, as described in Note 2 of the Financial Statements, BC Hydro changed its accounting policy related to the presentation of electricity imports and electricity exports. As a result, the comparative period 2022/23 was restated.

2 In 2021/22, certain amounts have been reclassified to conform to the 2022/23 presentation.

3 Other operating expenses consists of personnel expenses, materials and external services, other costs (net of recoveries), and capitalized costs as per the operating expenses note in the consolidated financial statements.

4 Consists of long-term debt, including the current portion, net of sinking funds and cash and cash equivalents.

OPERATING STATISTICS

for the years ended or as at March 31	**2026**	2025	2024	2023[1]	2022
Generating Capacity (megawatts)					
Hydroelectric	**13,271**	12,808	12,041	12,041	12,027
Thermal	**177**	177	176	174	179
Total	**13,448**	12,985	12,217	12,215	12,206
Peak One-Hour Integrated System Demand (megawatts)	**9,945**	10,476	11,363	10,977	10,787
Number of Domestic Customer Accounts					
Residential	**2,067,174**	2,024,503	1,990,321	1,961,208	1,931,041
Light industrial and commercial	**230,673**	228,483	226,151	223,915	221,573
Large industrial	**208**	204	204	203	201
Other	**3,453**	3,425	3,380	3,367	3,387
Total	**2,301,508**	2,256,615	2,220,056	2,188,693	2,156,202
Domestic Electricity Sold (gigawatt-hours)					
Residential	**19,371**	19,345	19,171	19,547	19,440
Light industrial and commercial	**19,406**	19,319	19,205	19,247	19,029
Large industrial	**15,132**	14,482	14,032	13,437	13,312
Other sales	**4,462**	3,608	3,005	7,649	1,671
Total	**58,371**	56,754	55,413	59,880	53,452
Net Electricity Exports/Imports (gigawatt-hours)					
Electricity exports	**1,613**	726	613	5,621	7,099
Electricity imports	**5,957**	9,082	14,212	3,988	1,120
Net Electricity Exports (Imports)	**(4,344)**	(8,356)	(13,599)	1,633	5,979
Net Electricity Export Revenues (Import Costs) (in millions)					
Electricity exports	**$ 60**	$ 32	$ 27	$ 728	$ 299
Electricity imports	**305**	528	1,377	644	67
Net Electricity Exports (Imports)	**(245)**	(496)	(1,350)	84	232
Revenues (in millions)					
Residential	**$ 2,490**	$ 2,405	$ 2,129	$ 2,146	$ 2,342
Light industrial and commercial	**2,143**	2,061	1,913	1,840	1,952
Large industrial	**1,026**	947	866	848	854
Other sales	**691**	636	596	1,148	471
Total Domestic	**6,350**	6,049	5,504	5,982	5,619
Trade	**1,244**	1,429	1,627	2,496	1,972
Total	**$ 7,594**	$ 7,478	$ 7,131	$ 8,478	$ 7,591

Average Revenue (per kilowatt-hour)

for the years ended or as at March 31	**2026**	2025	2024	2023	2022
Residential	**12.9¢**	12.4¢	11.1¢	11.0¢	12.0¢
Light industrial and commercial	**11.0**	10.7	10.0	9.6	10.3
Large industrial	**6.8**	6.5	6.2	6.3	6.4
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**9,468**	9,637	9,703	10,044	10,158
Lines In Service					
Distribution (kilometres)	**60,898**	60,650	60,474	60,289	60,093
Transmission (circuit kilometres)	**20,282**	20,223	20,198	20,192	20,148

[1]In 2023/24, as described in Note 2 of the Financial Statements, BC Hydro changed its accounting policy related to the presentation of electricity imports and electricity exports. As a result, the comparative period 2022/23 was restated.

TOTAL ELECTRICITY SALES AND SOURCES OF SUPPLY

for the years ended March 31	**2026**			2025			2024			2023[1]			2022		
	Generating Capacity (megawatts)	**Gigawatt-Hours**	**%**	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%
Electricity Sales															
Domestic	**13,448**	**58,371**	**80.8**	12,985	56,754	80.6	12,217	55,413	79.4	12,215	59,880	77.7	12,206	53,452	70.3
Electricity trade		**8,832**	**12.2**		8,438	12.0		10,118	14.5		12,018	15.6		17,836	23.5
		67,203	**93.0**		65,192	92.6		65,531	93.9		71,898	93.4		71,288	93.8
Line loss and system use		**5,066**	**7.0**		5,214	7.4		4,259	6.1		5,119	6.6		4,709	6.2
		72,269	**100.0**		70,406	100.0		69,790	100.0		77,017	100.0		75,997	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,857**	**10,179**	**14.1**	2,857	12,365	17.6	2,857	8,824	12.6	2,857	13,497	17.5	2,857	15,626	20.6
Revelstoke	**2,480**	**7,931**	**11.0**	2,480	7,073	10.0	2,480	6,148	8.8	2,480	9,410	12.2	2,480	8,548	11.2
Mica	**2,746**	**7,224**	**10.0**	2,746	6,247	8.9	2,746	5,282	7.6	2,746	8,733	11.3	2,746	7,681	10.1
Kootenay Canal	**583**	**2,491**	**3.4**	583	2,410	3.4	583	2,245	3.2	583	2,300	3.0	583	2,780	3.7
Peace Canyon	**694**	**2,488**	**3.4**	694	2,982	4.2	694	2,214	3.2	694	3,319	4.3	694	3,791	5.0
Seven Mile	**805**	**3,029**	**4.2**	805	2,415	3.4	805	2,549	3.7	805	2,906	3.8	805	2,936	3.9
Bridge River	**491**	**2,006**	**2.8**	491	2,162	3.1	491	2,070	3.0	491	2,588	3.4	478	2,578	3.4
Site C	**1,230**	**3,574**	**4.9**	767	1,308	1.9	-	-	-	-	-	-	-	-	-
Other	**1,385**	**4,276**	**5.9**	1,385	3,898	5.5	1,385	3,641	5.2	1,385	3,384	4.4	1,384	4,125	5.2
	13,271	**43,198**	**59.7**	12,808	40,860	58.0	12,041	32,973	47.3	12,041	46,137	59.9	12,027	48,065	63.1
Thermal generation	**177**	**149**	**0.2**	177	111	0.2	176	105	0.2	174	174	0.2	179	125	0.2
Purchases from Independent Power Producers		**14,219**	**19.7**		12,920	18.4		13,667	19.6		15,409	20.0		16,824	22.1
Non-integrated energy purchases		**124**	**0.2**		120	0.2		115	0.2		117	0.2		119	0.2
Market purchases		**14,789**	**20.5**		17,520	24.9		24,288	34.8		16,005	20.8		11,857	15.6
Other		**(210)**	**(0.3)**		(1,126)	(1.7)		(1,358)	(2.1)		(825)	(1.1)		(993)	(1.3)
	13,448	**72,269**	**100.0**	12,985	70,406	100.0	12,217	69,790	100.0	12,215	77,017	100.0	12,206	75,997	100.0

[1] In 2023/24, as described in Note 2 of the Financial Statements, BC Hydro changed its accounting policy related to the presentation of electricity imports and electricity exports. As a result, the comparative period 2022/23 was restated.