British Columbia Hydro and Power Authority

2022/23
Annual Service Plan Report

August 2023

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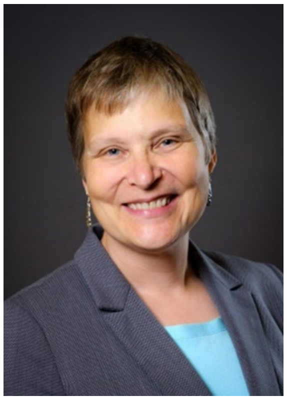
Board Chair's Accountability Statement



The BC Hydro 2022/23 Annual Service Plan Report compares the organization's actual results to the expected results identified in the 2022/23 – 2024/25 Service Plan published in 2022. The Board is accountable for those results as reported.

Signed on behalf of the Board by:

Lori Wanamaker
Board Chair
August 14, 2023

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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 year ending March 31, 2023. This letter provides an overview of highlights from the past year, as well as information on BC Hydro's reporting relationship as a Crown Corporation.

As climate change, technological advances and the evolution of customer energy use continued to transform our business, we implemented our Five-Year Strategy to maintain the service our customers count on, while looking to the future of our industry, company and work. This year, we focussed on electrification, advancing reconciliation with Indigenous Peoples and helping B.C.'s economy recover from the effects of COVID-19.

We acted upon the outcomes and recommendations from Phase 1 and Phase 2 of the Comprehensive Review of BC Hydro to position our company for future success while meeting the Province's climate goals and controlling our costs to keep rates affordable for British Columbians. To make it easier and more affordable for people to efficiently use more of B.C.'s clean electricity instead of fossil fuels to power their homes, businesses and vehicles, BC Hydro worked with the Province to implement our Electrification Plan – A clean future powered by water. The plan includes new programs and incentives to advance the switch from fossil fuels to clean electricity in homes and buildings, vehicles and fleets, businesses and industry, and to attract new innovative industries to B.C.

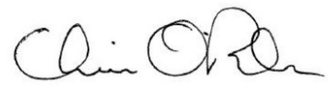
We have the important responsibility of keeping electricity rates affordable for our customers and funding necessary investments in our system. We advanced affordability initiatives to help our customers save money on their electricity bills and focussed on making it easier for our customers to do business with us. To ensure British Columbians continued to receive the reliable and clean electricity that is vital to the province's economic prosperity and climate objectives, we invested approximately $3.9 billion in 2022/23 to upgrade aging assets and build new infrastructure.

We also managed Site C within the revised budget of $16 billion. Throughout the year, project construction progressed, and the project is now nearly 75 per cent complete.

BC Hydro worked closely with the Ministry of Energy, Mines and Low Carbon Innovation (EMLI) to ensure alignment with Government policy expectations through regular meetings and updates. These were held between BC Hydro and EMLI Executives, as well as with the Minister and her staff, as appropriate, to discuss actions identified by the Province.

To support Board of Directors' training and development, we continued to deliver an orientation program aimed at increasing their familiarity with the Corporation, our industry and the unique responsibilities of Crown Corporation Directors, as well as equipping them with sufficient information and resources to make fully informed decisions. Directors were also provided with ongoing development opportunities that include special site visits to provide them with additional insight into the Corporation's operations.

We are proud of our accomplishments this year. We will continue to work together to ensure that our workforce goes home safely, every day, while we work towards our vision of a cleaner, more sustainable future for all British Columbians.



Lori Wanamaker
Board Chair
August 14, 2023

Chris O'Riley
President & CEO
August 14, 2023

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 2020 and expanded upon in the Board Chair's 2021/22 Mandate Letter from the Minister Responsible shaped the goals, objectives, performance measures and financial plan outlined in the BC Hydro 2022/23 – 2024/25 Service Plan and the actual results reported on in this annual report.

Purpose of the Organization

BC Hydro's mission is that we are here to safely provide our customers with reliable, affordable, clean electricity. We are one of the largest energy suppliers in Canada, generating and delivering electricity to 95 per cent of the population of British Columbia. We operate an integrated system backed by 30 hydroelectric plants and two thermal generating stations, as well as approximately 80,000 kilometres of transmission and distribution lines. Our partnership with B.C.'s clean energy industry encompasses approximately 125 generation projects across the province, including biomass, hydro, wind and solar generating facilities. 98 per cent of our electricity comes from clean or renewable sources.

As a provincial Crown Corporation, the owner and sole shareholder of BC Hydro is the Province of British Columbia. BC Hydro reports to the Provincial Government through the Minister of EMLI and the Government's expectations are expressed through the Board Chair's 2021-22 Mandate Letter and the following legislation and policy:

- The *Hydro and Power Authority Act*
- The *Utilities Commission Act*
- The *BC Hydro Public Power Legacy and Heritage Contract Act*
- The *Clean Energy Act (CEA)*
- CleanBC and the CleanBC Roadmap to 2030

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. Powerex is a key participant in wholesale energy markets across North America, trading wholesale power and natural gas, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), ancillary energy services and financial energy products. Powertech is internationally recognized for its technical expertise in a range of fields related to the electric utility and clean energy industries and offers services and solutions to energy clients, including BC Hydro, and other sectors globally. For more information on Powerex, Powertech and other active and inactive subsidiaries, see *Appendix B: Subsidiaries and Operating Segments*.

Operating Environment

As a utility that operates in a high hazard industry, we keep safety at the centre of everything we do. Our job is to safely keep the lights on for the people of B.C., and that means that every person working for BC Hydro and interacting with our system goes home safely each day. We are continuously working to improve our performance by sustaining and strengthening our Safety Framework.

In 2022/23, climate change and extreme weather continued to affect our business. In December 2022, intense cold led to two days of record-breaking electricity demand on BC Hydro's system. On December 21, 2022, BC Hydro set a new record for power consumption when demand peaked to more than 10,900 megawatts, shattering the record that was set the previous day by more than 15 per cent. Despite the significant increase, BC Hydro was able to meet demand for electricity across the province this winter because of our large integrated hydroelectric system.

The south coast of the province experienced drier conditions than normal in the late summer and fall of 2022/23, leading to historically low inflows at many of its smaller facilities in the Lower Mainland and on Vancouver Island. BC Hydro experts worked behind the scenes to manage these difficult conditions by using storage and planning releases to provide protection to downstream river flows. While many of BC Hydro's smaller systems in the Lower Mainland and on Vancouver Island were under pressure, BC Hydro was able to continue to meet demand for electricity. British Columbians benefited from our integrated, provincial electricity system to send power across the province.

In November 2022, strong winds and heavy rain caused outages to approximately 330,000 customers on Vancouver Island, the Gulf Islands, the Sunshine Coast and the Lower Mainland. The strong winds knocked down trees and branches – many of them weakened by the summer's drought – causing them to come into contact with BC Hydro's electrical equipment. As a result, crews worked around-the-clock to restore power, replacing dozens of spans of power line, power poles, transformers and cross-arms. Despite the extensive damage in some areas, crews were able to restore power to approximately 83 per cent of customers within 24 hours and 98 per cent within 48 hours. BC Hydro is proud of how our company responded and the quick restoration of service to the majority of our customers during this storm.

To help British Columbians manage expenses at a critical time when global inflation was driving higher costs for families and businesses, the Province announced that eligible BC Hydro customers would receive a one-time bill credit in the fall of 2022. Most residential customers received a one-time bill credit of $100, and business customers received an average credit between $350 to $500.

Throughout 2022/23, BC Hydro supported the Province's CleanBC Roadmap to 2030, which commits B.C. to reduce climate pollution and build a cleaner, stronger economy for people throughout the province and draws on BC Hydro's supply of clean and affordable hydroelectric power to reduce greenhouse gas (GHG) emissions. In March 2023, the Province made a significant announcement regarding the issuing of an Environment Assessment Certificate for Cedar LNG and the establishment of a new energy action framework, including a new BC Hydro task force to accelerate the electrification of B.C.'s economy.

BC Hydro's electricity system was largely built in the 1960s, 1970s and 1980s and we invested approximately $3.9 billion last year to upgrade aging assets and build new infrastructure. There are hundreds of BC Hydro capital projects underway that, together, make up one of the largest expansions of electrical infrastructure in British Columbia's history. During 2022/23, BC Hydro capital projects placed in-service totaled $1.4 billion, including projects to renew and expand our generation, transmission and distribution systems.

Report on Performance: Goals, Objectives, and Results

Goal 1: Deliver Reliable Power Safely

Objective 1.1: BC Hydro will safely and reliably meet the evolving expectations of our customers by prudently planning and investing in the system and improving our service.

As a utility that operates in a high hazard industry, our goal continues to be that everyone goes home safely, every day. By continuing to make strategic investments to expand our system and maintain aging infrastructure, we will ensure we can continue to safely provide our customers with reliable and clean electricity, while continuing to meet the rising expectations of our customers.

Key results

- As of March 31, 2023, BC Hydro had gone more than 12 years without a fatality - maintaining the longest period without a fatality in over 31 years of recorded data.
- Targets for our customer reliability measure, System Average Interruption Duration Index and System Average Interruption Frequency Index, were met despite experiencing several challenging weather events throughout the year.
- Achieved a Customer Satisfaction Index result of 89 per cent with consistent results in our residential and commercial customer segments.
- Exceeded the Key Generating Facility Forced Outage Factor target, demonstrating the effectiveness of our capital and maintenance investment strategies to ensure the reliability of our generating system for our customers.

Summary of progress made in 2022/23

Preventing serious injury incidents and meeting our target of Zero Fatalities and Serious Disabling Injuries remained our top priority. Our investments in safety have improved our safety performance to zero fatalities since 2010.

Our most common sources of lost time injury are slips, trips, and falls and musculoskeletal stress and strain. BC Hydro has programs to address these, including our ergonomics program, for proactive identification and mitigation of office and field musculoskeletal injuries, and our annual winter hazards safety awareness campaign, which targets our most common source of slips, trips and falls.

Although we continued to experience increasingly challenging weather events throughout the year, we maintained customer reliability through monitoring and planning for overall system reliability. In 2022/23, BC Hydro successfully responded to a number of storms that tested our capability to respond to major events and continued to maintain customer reliability through monitoring and planning for overall system reliability. We also responded to and recovered from multiple events including wildfires and asset failures to ensure ongoing system reliability and resilience. Throughout the year, BC Hydro completed a number of planned outages to conduct maintenance to maintain system reliability and undertook strategic vegetation management to address high risk tree-related outages.

BC Hydro has consistently met its Key Generating Facility Forced Outage Factor targets, demonstrating the effectiveness of our capital and maintenance investment strategies to ensure the reliability of our generating system. In 2022/23, we continued to focus on returning equipment to service in a timely manner, minimizing the duration of forced outages and performing root cause analyses when outages occurred to understand the cause and prevent reoccurrence of similar outages.

We worked to consistently improve customer experience and meet growing customer expectations and once again, exceeded our Customer Satisfaction Index threshold in 2022/23. This result reflects our ongoing efforts in ensuring high customer reliability, continued commitment to customer service and improvements in our customer communications. In 2022/23, BC Hydro provided approximately 3,000 Customer Crisis Fund grants to customers facing emergency financial situations and disconnection with financial assistance of up to $600 to pay their bill to enable the continued supply of energy.

Performance measures and related discussion

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
1.a Zero Fatality & Serious Disabling Injury[1,2] [Loss of life or the injury has resulted in a permanent disability]	1[3]	0	0

Data source: The data source for all safety performance metrics are incidents reported through our Incident Management System.
[1]PM 1.a targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 0 and 0, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.
[2]BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.
[3]This was a serious employee electrical contact incident that occurred in June 2021 resulting in a permanent disability.

Zero Fatality and Serious Disabling Injury is a measure of electrical contact, fall from height, mechanical energy or transportation incidents that have resulted in a loss of life or an injury resulting in a permanent disability for which a disability pension has been received or is expected. In 2022/23, BC Hydro achieved its performance target for Zero Fatality and Serious Disabling Injury performance measure.

To ensure accuracy and reliability of the data, each incident reported through our Incident Management System is reviewed to ensure the correct injury category and seriousness has been assigned. The measure of Zero Fatality and Serious Disabling Injury is unique to BC Hydro and is not benchmarked against other Electricity Canada member utilities. Electricity Canada does not report on fatalities on an annual basis.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
1.b Lost Time Injury Frequency[1,2] [Number of employee injury incidents resulting in lost time (beyond the day of injury) per 200,000 hours worked]	0.87	0.74	0.86

Data source: The data source for all safety performance metrics are incidents reported through our Incident Management System.
[1]PM 1.b targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 0.74 and 0.74, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website
[2]BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

Lost Time Injury Frequency (LTIF) is an indicator of the likelihood of a full-time employee sustaining a time loss injury in a normal work year. Lost time injuries are those where the employee was absent from work beyond the day of injury.

We did not meet our LTIF target of 0.74 and finished 2022/23 with 50 lost time injuries that resulted in a rate of 0.86. Throughout the year, we worked with specific key business units to develop plans and interventions to reduce these types of injuries.

To ensure accuracy and reliability of the data, each incident reported through our Incident Management System is reviewed to ensure the correct injury category and seriousness have been assigned. LTIF is an internationally recognized metric, and we benchmark our LTIF performance against available Electricity Canada composite results.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
1.c SAIDI (System Average Interruption Duration Index)[1,2] [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year (excluding major events)]	3.50	3.30	3.14

Data source: BC Hydro reliability information is collected in a centralized database that allows outage records to be reviewed by managers regularly to ensure accuracy. Outages that impact a significant number of customers or involve lengthy repair times require a formal outage report to be written by an engineer and approved by management.

[1]PM 1.c targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 3.35 and 3.35, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

[2]Annual targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans. 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 uncontrollable elements that can significantly disrupt the electrical system. The reliability targets are, therefore, based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

System Average Interruption Duration Index (SAIDI) is the length of time that an average customer will be without power, in any given time period and includes both planned and forced outages. We exceeded our 2022/23 SAIDI target by 4.8 per cent, with a result of 3.14 total hours of sustained interruption experienced by an average customer in a year, compared to a target of 3.30 hours. BC Hydro completed a high number of planned outages to maintain system reliability and focused on providing customers with advance notice of outages to minimize impacts.

The data to measure our reliability performance measures is collected and validated in a process that starts with operational staff recording the start and end time of each power outage, as well as the cause. Based on the location of the outage, the number of customers impacted is calculated automatically.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
1.d SAIFI (System Average Interruption Frequency Index)[1,2] [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.54	1.38	1.50

Data source: BC Hydro reliability information is collected in a centralized database that allows outage records to be reviewed by managers regularly to ensure accuracy. Outages that impact a significant number of customers or involve lengthy repair times require a formal outage report to be written by an engineer and approved by management.

[1]PM 1.d targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 1.38 and 1.38, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

[2]Annual targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans. 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 uncontrollable elements that can significantly disrupt the electrical system. The reliability targets are, therefore, based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

System Average Interruption Frequency Index (SAIFI) is a utility standard measure of the number of sustained interruptions,longer than one minute,an average customer will experience over the course of a year, excluding major events. We met our 2022/23 SAIFI target, within the 10 per cent margin, with a result of 1.50. More than half of all outages in the province are caused by adverse weather causing trees and vegetation to come into contact with our system.

Annually, circuits are benchmarked to prioritize investment for sustained reliability improvement on the worst performing circuits. The most significant outages are reviewed regularly to ensure accuracy of data, effectiveness of restoration actions, and to better understand vulnerabilities. As a second check for accuracy, trends in recent performance measures are compared against past results and forecast performance. Our Reliability Improvement team reviews the monthly performance measures and acts when actual performance deviates from forecast.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
1.e Key Generating Facility Forced Outage Factor (%)[1]	1.03	1.80	1.05

Data source: BC Hydro has seven key generating facilities which are defined as BC Hydro operated plants with installed capacity greater than 200 MW. Together, they provide 90 per cent of the average annual electricity generated by BC Hydro's facilities. The objective is to keep the Forced Outage Factor below 1.80 of the total number of hours per year.
[1]PM 1.e targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 1.80 and 1.70, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Key Generating Facility Forced Outage Factor measures the percentage of time key generating units are unavailable when they are needed due to internal unplanned causes and is an important measure of the ongoing reliability of the generating system. Annually, the Forced Outage Factor can be relatively volatile, and applying the historical 60-month rolling average smooths the range to provide a more stable measure for which targets can be set.

We achieved the target to remain below 1.80 per cent for Key Generating Facility Forced Outage Factor with a result of 1.05 per cent, demonstrating the continued effectiveness of our maintenance and capital investment programs.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
1.f CSAT Index[1] [Customer Satisfaction Index: % of customers satisfied or very satisfied]	91.0	85.0	89.0

Data source: Customer Satisfaction (CSAT) is an index that measures residential, commercial and key account customers' levels of satisfaction. The index is comprised of five key drivers: value for money; commitment to customer service; providing reliable electricity; acting in the best interest of British Columbians; and efforts to communicate to customers and communities. BC Hydro conducts quarterly surveys of residential, commercial, and key account customers and the index is weighted equally across the three customer types.
[1]PM 1.f targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 85 and 85, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

The Customer Satisfaction (CSAT) Index measure gauges the degree to which BC Hydro is meeting customers' electricity and service needs. Our 2022/23 CSAT result of 89 per cent exceeds the target of 85 percent reflecting our ongoing efforts in ensuring customer reliability and continued commitment to customer service and improving customer communications. The stable target for the CSAT index reflects that customers' service needs are being met; however, continued effort is necessary to address gaps in specific areas, as well to meet customer's changing expectations from their interactions with other organizations. In the near term, BC Hydro does not have any planned investments that would result in a sustained increased to the index.

The residential and commercial customer 2022/23 CSAT index scores were relatively consistent with past years' results. However, key account customers' 2022/23 CSAT index scores index fell below 90 per cent for the first time in over a decade, due to unexpected broader economic difficulties experienced by many B.C. companies.

Goal 2: Grow our Load

Objective 2.1: BC Hydro will maintain and efficiently grow our load to help keep rates affordable and competitive for our customers and support achieving British Columbia's climate action targets.

We are focussed on encouraging customers to switch to BC Hydro's clean electricity to electrify British Columbia's growing economy and support the reduction of GHG emissions to meet the Province's climate targets.

Key results

- Advanced the Integrated Resource Plan, which details how BC Hydro will meet future electricity requirements, by updating policies and legislation, fluctuations in customer demand and changes in our resources.
- In February and March 2023, submitted rate design applications to the BC Utilities Commission (BCUC) to remove barriers to electrification and help our customers save money.
- In February 2023, initiated an Expression of Interest to gauge industry's electricity needs in the North Coast region of B.C. to inform plans for new transmission infrastructure and unlock the economic potential of the region.
- Signed three new industrial customer project incentive agreements that will result in a reduction of 216,000 tonnes of GHG emissions per year.
- Implemented the Clean Electricity Standard to ensure we have produced or acquired sufficient clean electricity to meet the needs of our domestic customers and are phasing out non-renewable energy purchase agreements by 2030.

Summary of progress made in 2022/23

In 2022/23, BC Hydro began to implement its Electrification Plan, A clean future powered by water. We will be investing $260 million over the next five years to advance the plan to make it easier and more affordable for people to efficiently use more of B.C.'s clean electricity instead of fossil fuels to power their homes, businesses and vehicles. The plan pursues electrification opportunities in three key areas: transportation, buildings and industry.

In 2022/23, BC Hydro installed 33 electric vehicle fast-charging stations at 26 sites. Since 2012/13, we have grown our public charging network, in collaboration with the Province, to 141 fast chargers at 83 sites across B.C. In the buildings sector, fuel switching heat pump installations increased by 366 per cent to approximately 3,500 in 2022/23, due to BC Hydro's incentive programs. Nineteen industrial customers completed fuel-switching energy studies to switch all or parts of their operations to clean hydroelectricity instead of fossils fuels to reduce GHG emissions.

The CleanBC Facilities Electrification Fund supports BC Hydro customers and their fuel switching projects that reduce GHG emissions and the cost of connecting into our clean electricity grid. BC Hydro does not administer this program; however, it promotes the program to customers through its Key Account and Business and

Economic Development teams and facilitates applications to the fund. In 2022/23, 14 BC Hydro customers submitted applications to the CleanBC Facilities Electrification Fund, and five were approved.

Over the past several years, the number of customer connection requests have risen significantly due to B.C.'s construction boom and electrification and BC Hydro has continued to improve our customer connections process, by improving the end-to-end customer experience, reviewing our distribution extension policy and building out infrastructure. We also began engaging with customers to gather feedback on our distribution extension policy and implemented measures to address localized capacity constraints, including updating feeder loading planning criteria in high growth areas.

We advanced rate proposals with the BCUC to help our customers save money and remove barriers to electrification. In February 2023, we requested approval of an optional time-of-use rate for the entire residential home, including electric vehicle charging. The proposed rate supports the efficient use of electricity to help participating customers save money on their bills by shifting electricity consumption from BC Hydro's system peak period to other hours of the day. We also submitted a Transmission Service Rate Design Application in March 2023 to transition the current stepped rate structure for industrial customers to a flat rate, helping to remove a barrier to electrification.

In 2022/23, we initiated our first province-wide capacity focused programs, Peak Saver/Peak Rewards, to shift customer electricity use out of BC Hydro's peak period. We also launched a Non-Wires Alternative project to address local constraints at the substation level, with the aim of deferring the need for new infrastructure.

Performance measures and related discussion

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
2.a Load Growth Supporting CleanBC (Gigawatt hours (GWh))[1,2] [Cumulative load growth in GWh to support CleanBC (fuel switching and new clean industries)	N/A	900	739

Data source: Annual load growth in gigawatt hours per year is measured and estimated for the various sectors such as: transportation; residential and commercial buildings; upstream gas and gas pipelines and other Industry, including mining, LNG, district energy; and new clean industry.
[1]PM 2.a targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 2,100 and 3,800, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.
[2]There is correlation between the Load Growth Supporting CleanBC and New Connected Commercial and Industrial Load performance measures since many new loads will also support CleanBC by reducing or avoiding GHG emissions.

Load Growth Supporting CleanBC tracks the growth in load related to CleanBC (fuel switching and new clean industries) and the progress of BC Hydro's strategy to electrify British Columbia's growing economy since 2020/21. BC Hydro did not meet its 2022/23 target of 900 GWh and finished the year with a result of 739 GWh. This result is largely due to factors outside BC Hydro's control, including delays to larger fuel switching projects and electric vehicle related load growth due to supply chain issues.

The measure of Load Growth Supporting CleanBC is unique to BC Hydro and is not benchmarked against other Electricity Canada member utilities.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
2.b New Connected Commercial and Industrial Load (Megawatts (MW))[1,2] [Cumulative additional MW from new or expanded commercial and industrial load]	N/A	185	535

Data source: This measure captures additional megawatts from the following types of load: new commercial and industrial connections; incremental load at existing sites that triggers a service upgrade or a change to the Electricity Supply Agreement; and new load from a new type of operation at a brownfield site.

[1]PM 2.b targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 500 and 625, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

[2]There is correlation between the Load Growth Supporting CleanBC and New Connected Commercial and Industrial Load performance measures since many new loads will also support CleanBC by reducing or avoiding GHG emissions.

This metric captures additional megawatts from new or expanded commercial and industrial load since 2020/21 and reflects BC Hydro's efforts to support load growth. Our 2022/23 result of 535 cumulative MW from new or expanded commercial or industrial load exceeded the 185 MW target. This result was due, in part, to a large industrial customer implementing a project that used BC Hydro's clean electricity to displace their use of diesel fuel and decrease their GHG emissions by 30 per cent.

Industrial projects account for most of the expected load growth and consequently, changes to in-service dates and load requirements can significantly impact this metric.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
2.c GHG Emissions Reduction Electrification (million tonnes CO2e/year)[1] [Cumulative GHG emissions reductions from fuel switching and new clean industries]	N/A	0.61	0.48

Data source: The GHG emissions reduced or avoided through electrification are calculated using project-specific estimates from BC Hydro program records where available or by applying average emission reduction factors to the load increase.

[1]PM 2.c targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 1.35 and 2.08, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

The GHG Emissions Reduction Electrification performance measure tracks GHG emission reduction from fuel switching and new clean industries, where the use of clean electricity displaces the use of more carbon intensive fuels since 2020/21.

BC Hydro did not meet its 2022/23 target of 0.61 million tonnes CO2e per year and finished the year with a result of 0.48 million tonnes CO2e per year. As was the case with the Load Growth Supporting CleanBC performance measure, this result is also largely due to factors outside BC Hydro's control, including delays to larger fuel switching projects and electric vehicle related load growth due to supply chain issues.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
2.d GHG Emissions Reduction – BC Hydro Operations (%)[1] [Cumulative GHG reductions from BC Hydro operations since 2007]	N/A	42	50

Data source: This measure tracks BC Hydro's progress in reducing GHG emissions related to our own operations in the following areas: fleet; buildings; air travel; gas insulated equipment (sulfur hexafluoride); Non-Integrated Areas (diesel generation), thermal (natural gas), generation and Independent Power Producers. Annual emissions will be measured in million tCO2e (tonnes) of carbon dioxide equivalent.

[1] PM 2.d targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 43 and 44, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

This metric informs how BC Hydro is supporting and aligning with the Province's climate goals to reduce the emissions related to our operations. We exceeded our target of 42 per cent with a year end of result of 50 per cent, largely due to lower than forecasted emissions from independent power producers and our thermal facilities. Annual emissions vary greatly dependent on weather patterns and operational factors outside of BC Hydro's control. Targets for this metric have been set to allow BC Hydro to exceed the 16 per cent provincial GHG emissions reduction target from 2007 levels by 2025.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
2.e Clean Electricity Standard (%)[1] [BC Hydro generated and acquired clean energy available to meet BC Hydro retail sales on the integrated grid over a fixed four-year period]	N/A	100	100

Data source: This measure incorporates BC Hydro generated clean energy, procured clean energy and net energy deliveries to the integrated power system associated with Powerex. A fixed four-year period of January 1, 2021 to December 31, 2024 has been chosen to balance annual variations in load and hydrology and is similar to the renewable procurement requirements in other jurisdictions.
[1]PM 2.e targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 100 and 100, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

The Clean Electricity Standard measures the percent of clean energy available to meet BC Hydro retail sales on the integrated grid over a fixed four-year period. It includes BC Hydro generated clean energy, procured clean energy and net clean energy deliveries to the integrated power system associated with Powerex. BC Hydro achieved its target of 100 per cent Clean Electricity Standard in 2022/23.

This metric helps confirm BC Hydro's ability to support provincial GHG emission reduction targets and CleanBC objectives while securing the Province's competitive position when offering surplus hydro capabilities to customers in external jurisdictions.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
2.f Customer Interconnection Studies Completed on Time (%) [Completion of interconnection studies to allow customers to connect to BC Hydro's system]	91	80	92

Data source: The target study delivery date for the various interconnection studies phases are compared to the actual completion dates to determine the percentage of customer interconnection studies completed on time.
[1]PM 2.f targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 80 and 80, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

The Customer Interconnection Studies Completed On Time tracks BC Hydro's performance of meeting the overall timeline for the completion of interconnection studies required for customers to be connected to our system. BC Hydro exceeded its 2022/23 target of 80 per cent with a result of 92 per cent of customer interconnections studies being completed on time. This result was achieved by strong management of customer timelines and proactively identifying risks. Although we have exceeded this target, we have maintained a target of 80 per cent given increasing volume and complexity of the interconnection studies and external factors, including changes initiated by customers and/or third parties and additional time required to accommodate feedback from stakeholders.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
2.g Demand Side Management Capacity (MW)[1,2] [Annual new incremental capacity (MW) savings from the energy conservation portfolio]	N/A	80	96

Data source: BC Hydro calculates annual associated capacity savings that are related to the BC Hydro energy conservation energy savings. The capacity saving targets measured in megawatts are derived from the Demand Side Management Plan and 2021 Integrated Resource Plan.
[1]PM 2.g targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 80 and 90, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.
[2]This measure informs the estimated reduction in system peak as measured at the customer meter.

Demand Side Management Capacity reflects the annual new incremental associated capacity savings from the energy conservation portfolio including programs, codes and standards, and conservation rates that measure BC Hydro's performance against annual energy targets. This measure also includes savings from capacity-focused initiatives such as programs and time-varying rates.

BC Hydro continued to have strong performance from our energy efficiency and conservation initiatives and exceeded the Demand Side Management Capacity target of 80 MW. In 2022/23, we continued to offer programs to support low-income customers, as well as customers in the non-integrated areas, and improved affordability for participating customers by helping them be more energy efficient and reduce their bills.

Goal 3: Control Our Costs

Objective 3.1: BC Hydro will manage costs to provide affordable and competitive rates.

This objective reinforces BC Hydro's efforts to maintain affordability while making strategic investments to maintain and expand our electricity system to support our customers.

Key results

- The Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, requested a bill increase of two per cent starting on April 1, 2023.
- BC Hydro's residential, commercial and industrial rates were ranked in the first quartile, based on an analysis of Hydro Quebec's annual report, 2022 Comparison of Electricity Rates in North America.
- Over the last five years, BC Hydro successfully delivered 217 capital projects at a total cost of $3.459 billion, which is 2.64 per cent under the aggregated budget of $3.553 billion and within the target of +/- 5 per cent of budget.
- In February 2023, the Site C Project reached a significant milestone when the first rotor, required to generate electricity, was successfully placed into the Unit 1 generator pit. The 600-tonne rotor took approximately one year to assemble and required two powerhouse cranes to lift it into place.
- BC Hydro worked with the Province to provide a "cost-of-living bill credit" to eligible customers. Credits were provided to all eligible residential and commercial electricity customers.

Summary of progress made in 2022/23

BC Hydro balances affordability for our customers with significant required investment in our electricity system, including operating and capital expenditures that support safety and reliable service. Our actions to keep rates low for our customers have resulted in our residential, commercial and industrial rates being ranked in the first quartile for 2022/23, based on analysis of Hydro Quebec's annual report, 2022 Comparison of Electricity Rates in Major North American Cities.

BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, requested an average annual bill increase of only 1.1 per cent – below the rate of forecasted provincial rate of inflation over the three-year period. This application reflects our continued efforts to deliver safe and reliable power, while keeping electricity affordable for our customers.

In 2022/23, BC Hydro's Project Delivery group actively managed approximately 300 projects. We continued to improve our project and portfolio performance reports, by leveraging historical project delivery information to support decision making and timely delivery of projects within budget. We also focused on streamlining processes to reduce cost and accelerate schedules for small capital projects that meet defined criteria, such as pre-existing alternatives analysis or where the scope has low complexity and/or risk.

Construction on Site C has been underway since July 2015. By the end of 2022/23, the project was approximately 75 per cent complete and remained on track to have all six generating units fully in-service by late 2025.

BC Hydro continued to manage the Site C project within the approved $16 billion budget. The delays and impacts related to the COVID-19 pandemic were the single largest estimated contributor to the cost increase in the project budget.

As of March 31, 2023, the life-to-date actual costs of the project were $11 billion, which results in a remaining budget of $5 billion. Key accomplishments this year included:

Construction activities: The Site C project advanced construction throughout the year, with some parts of the project already completed or nearing completion. The earthfill dam was about 90 per cent complete as of March 2023. Additionally, the final segment for the last penstock unit was placed into the powerhouse. Significant progress also occurred on the Highway 29 realignment when the Halfway River Bridge, the fifth and final new bridge, opened to traffic in March 2023. All six segments of Highway 29 that were realigned are open to traffic.

Work on the 2.6-kilometre-long Hudson's Hope shoreline protection berm was completed in November 2022.

Indigenous relations: Throughout the year, BC Hydro continued to engage, build relationships and find solutions together on topics that are most important to the Indigenous communities affected by Site C. Six environmental forum meetings, including three field tours, occurred with Indigenous communities to share information about environmental programs and projects. BC Hydro also hosted numerous community open houses in First Nations communities, boat tours of the Peace River, Highway 29 and dam site tours, and provided quarterly updates on the timing and process of reservoir filling.

Since the beginning of the project, approximately $700 million in procurement opportunities have been awarded to Indigenous designated companies.

Right bank foundation enhancements: The project continued to implement foundation enhancements to address the geotechnical challenges in the bedrock foundation on the project's right bank. Construction of the powerhouse and spillways piles were completed.

Ongoing reviews by the Technical Advisory Board and independent dam experts continued to confirm that the design of the foundation enhancements meets the highest safety standards and international best practices.

Project workforce: In October 2022, employment on the project peaked at 5,554 workers. In March 2023, there were 5,233 people working on the Site C project, including 3,597 workers from British Columbia (69 per cent of the total workforce), 419 Indigenous workers, 522 women and 905 workers from the Peace River Regional District.

Community benefits: As of March 31, 2023, 83 projects had received nearly $730,000 as part of the Generate Opportunities Fund. In addition, the BC Hydro Peace Agricultural Compensation Fund distributed more than $2.7 million to 82 projects to date.

Project oversight: To ensure the Site C project is developed on time and on budget, an independent expert Project Assurance Board advises the project team. The Project Assurance Board provides enhanced oversight to contract procurement and management, project deliverables, safety, environmental integrity and quality assurance. The Project Assurance Board is made up of BC Hydro directors, independent experts and government representatives.

The Site C Project Assurance Board continued to provide independent expert advice on the project. There were 12 Project Assurance Board meetings, two workshops and one site tour held in 2022/23.

BC Hydro worked collaboratively with the Project Assurance Board, special advisor Peter Milburn, Ernst and Young Canada, the Technical Advisory Board, and independent international dam experts to actively manage ongoing project risks.

The Technical Advisory Board and independent international dam experts continued to review and confirm the project designs are appropriate, safe and serviceable over the long operating life of Site C.

Performance measures and related discussion

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
3.a Affordable Bills – Residential[1,2]	1st quartile	1st quartile	1st quartile
3.b Affordable Bills – Commercial[1,2]	1st quartile	1st quartile	1st quartile
3.c Affordable Bills – Industrial[1,2]	1st quartile	1st quartile	1st quartile

Data source: the Affordable Bills measures are based on BC Hydro's rankings in the residential, commercial and transmission service rate categories in the annual Hydro Quebec report, Comparison of Electricity Prices in Major North American Cities. The report is used as a benchmark to demonstrate that our bills are affordable compared to other major North American utilities.]

[1]PM 3.a, 3.b and 3.c targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 1st quartile and 1st quartile, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

[2]Pursuant to Rate Comparison Regulation under the *Clean Energy Act*, Ministerial Act No. 167, issued on June 28, 2011, BC Hydro provides an Electricity Rate Comparison Annual Report to the Minister of Energy, Mines and Low Carbon Innovation.

The Affordable Bills measures are based on BC Hydro's rankings in the residential, commercial and transmission service rate categories in the annual Hydro Quebec Report. The report is used as a benchmark to demonstrate that our bills are affordable compared to other major North American utilities. Based on an analysis of Hydro Quebec's annual report, 2022 Comparison of Electricity Rates in North America, BC Hydro's residential, commercial and industrial rates were ranked in the first quartile.

The methodology for calculating these performance measures uses the median consumption level for the residential and commercial performance measures and the largest consumption level for the industrial performance measure. Median consumption level provides a better representation of the central tendency than average and the largest consumption level provides the best indication of BC Hydro's performance regarding rate competitiveness for large industrial customers.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
3.d Project Budget to Actual Cost: Cumulative Five Years[1]	-4.76% on $4.35 billion	Within +5% to -5% of budget excluding project reserve amounts	-2.64% on $3.553 billion

Data source: This measure compares actual project costs at completion to the original approved full scope implementation budgets, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period. This measure includes Dam Safety, Generation, Transmission Line, Substation as well as major Distribution and Property projects, managed by BC Hydro Capital Infrastructure Project Delivery.

[1]PM 3.d targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as within +5% to-5% of budget excluding project reserve amounts and within +5% to-5% of budget excluding project reserve amounts, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

BC Hydro measures its performance in delivering capital projects with the Project Budget to Actual Cost measure. Since its introduction in 2015/16, BC Hydro has consistently met its yearly target of being within +5 per cent to -5 per cent of the project budget, not including project reserve amounts. Over the last five years, BC Hydro successfully delivered 217 capital projects at a total cost of $3.459 billion, which is 2.64 per cent under the aggregated budget of $3.553 billion and within the target of +/- 5 per cent of budget.

Project Budget to Actual Costs is measured using a five-year rolling data set of actual costs compared to original approved full scope implementation budgets in aggregate, excluding project reserve funds, for capital projects that were put into service during the period. The +/- 5 per cent target is the same over the plan period, as it is the objective to have the entire project portfolio in-service within this actual cost range.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
3.e Site C – Cost[1] [Total expected cost at or below approved budget]	$16 billion	$16 billion	$16 billion

Data source: The output from the Cost Risk Analysis is identified and compared to the approved budget of $16 billion.

[1]PM 3.e targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as $16 billion and $16 billion, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

The Site C - Cost: measures how we are progressing against our cost objectives for the Site C Project. Site C is the biggest capital project at BC Hydro; therefore, the outcome of this measurement informs how well BC Hydro is able to estimate and scope major capital projects, and how well we can keep project variables within budget.

BC Hydro remains on track to complete Site C within the approved budget of $16 billion. In 2022/23, the project progressed and is now nearly 75 per cent complete. However, cost risks remain based on the work that still needs to be completed.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
3.f Site C – Schedule[1] [On or before first power date]	December 2024	December 2024	December 2024

Data source: The output from the Schedule Analysis is identified and compared to the approved first power date of December 2024.
[1]PM 3.f targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as December 2024 and December 2024, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Site C - Schedule measures how we are progressing against our schedule objectives for the Site C Project. Site C is the biggest capital project at BC Hydro; therefore, the outcome of this measurement informs how well BC Hydro is able to estimate and scope major capital projects, and how well we can keep project variables within schedule.

The Site C project is now nearly 75 per cent complete and BC Hydro remains on track to complete it within the approved schedule of first power in December 2024. However, schedule risks remain based on the work that still needs to be completed.

Goal 4: Strengthen Our Resilience and Agility

Objective 4.1: BC Hydro will enhance preparedness for threats like cybersecurity attacks, impacts of climate change, natural disasters and global pandemics to increase our strength and resilience to challenging conditions.

As external factors increasingly add to the complexity of our work, we are strengthening our abilities to prevent disruptions to the essential service we provide our customers, manage through challenges and position our company to take advantage of opportunities when they arise.

Key results

- Achieved an 80 per cent reduction in Mandatory Reliability Standards non-compliances compared to 2020/21, exceeding the 60 per cent reduction target for 2022/23.
- Provided public education to 7,860 participants through our online and in-person Public Electrical Safety Awareness Training course.
- Operations technical employees completed an average of 49 hours of annual training to maintain the skills required to work safely and efficiently and maintain system reliability, exceeding the 2022/23 target.

- Established an Accessibility Committee and drafted an Accessibility Plan to help us identify barriers to access and make recommendations on how to remove and prevent them to ensure compliance with the *Accessible British Columbia Act* and strengthen our inclusivity.

Summary of progress made in 2022/23

Training and development, robust compliance, financial discipline and strong safety performance support resilience and ensure our people assets and facilities are safe.

In 2022/23, there was considerable progress with the Mandatory Reliability Standards program. BC Hydro implemented controls to reduce reliability, reputational and financial risks that resulted in strengthening our Mandatory Reliability Standards compliance throughout the company. Throughout the year, we continued to mature our compliance program practices and internal controls to comply with Mandatory Reliability Standards, including improving the Critical Infrastructure Protection program. We also implemented vegetation management improvements that ensured that BC Hydro was fully compliant with the Mandatory Reliability Standards.

We updated over 200 emergency and continuity plans used to support preparations and response to any significant disruptive events that may impact our ability to meet operational and business needs. We also conducted 44 exercises and closed 19 corrective actions to test and continually improve plans and procedures to strengthen our resilience.

At BC Hydro we believe that the diversity of our workforce should reflect the diversity of the customers and the communities we serve. In 2022/23, we introduced hiring targets and refreshed our employer brand to increase the diversity of qualified candidates to BC Hydro. To ensure a respectful and inclusive workplace, all managers receive training on how to be an inclusive leader and employees and contractors are trained on their roles in creating an inclusive workplace.

To ensure all our leaders had access to inclusion and diversity leadership training that met their needs, we developed a custom version of the course targeting crew leads, delivered by a seasoned field trainer. The content covers key concepts of the original course, using field-specific scenarios and addresses persistent myths and misconceptions about inclusion and diversity.

We also implemented a flexible work model for our office-based employees and conducted three pulse check surveys to understand their experience and support ongoing sustainment of the model.

Performance measures and related discussion

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
4.a Employee Engagement Index (% index)[1]	83 Above Global Utility Index	At or above Global Utility Index	83 Above Global Utility Index

Data source: All data is collected and generated from the confidential biennial survey, administered by PwC, with survey items being ranked on a five- point scale. Results are presented based on Percent Favourable score (Tend to agree and Agree).

[1]PM 4.a targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as at or above Global Utility Index and at or above Global Utility Index, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Employee Engagement Index measures the extent to which employees are motivated to contribute to business success and are willing to apply discretionary effort to accomplishing tasks important to the achievement of business goals. An engaged workforce can have a significant effect on financial and operational results.

In 2022/23, the result of the biennial employee engagement, survey administered by PwC, was 83 per cent, which exceeds the Global Utility Index. BC Hydro compares our employee engagement survey results to benchmarks of global utilities provided by PwC.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
4.b Workforce Diversity (%)[1] • Women • Visible Minority • Indigenous People • Persons with Disabilities	• 32.0 • 27.6 • 4.1 • 3.7	• 30.0 • 25.0 • 4.3 • Progress towards 10	• 32.6 • 28.0 • 4.0 • 3.7

Data source: Employees respond to an optional survey, administered and maintained by BC Stats to self-identify their ethnicity when they join BC Hydro. The targets are based on available B.C. workforce in the subset of the labour market in the occupations BC Hydro hires, as derived from the current census.

[1]PM 4.b targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 30; 25; 4.6 and progress towards 10 and 30, 25 and 4.9 and progress towards 10, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Workforce Diversity is a measure of BC Hydro's workforce in the representation of women, visible minorities, Indigenous people and people with disabilities.

BC Hydro did not achieve the 2022/23 Workforce Diversity targets. While we exceeded our 2022/23 targets for women and visible minorities; we did not meet the Indigenous people and persons with disabilities targets. Consequently, this measure was not achieved, as all the targets need to be met or exceeded.

BC Hydro gained 22 Indigenous employees since the beginning of the year, bringing the total of self-identified Indigenous employees in our workforce to 4 per cent, which was below target but higher than the available B.C. workforce of 3.6 per cent in the occupations that we hire. BC Hydro also gained 23 self-identified employees with disabilities since the beginning of the year. However, due to increased headcount in 2022/23, the percentage of self-identified persons with disabilities remained at 3.7 per cent. We measured the participation of the four designated groups by their representation as compared to the available workforce in B.C. for the occupations that BC Hydro employs.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
4.c Inclusion and Diversity Leadership Training (% complete)[1]	36	75	73

Data source: Results are determined by tracking participation of BC Hydro people leaders in the LEAD-133VT – Inclusive Leadership course at BC Hydro.

[1]PM 4.c targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 100 and 100, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Inclusion and Diversity Leadership Training is a measure that assesses the progress of people leaders completing leadership modules on the following topics: bias and diversity; safety and diversity and supporting mental health. This measurement tracks the number of people leaders that have completed the training to help them create an inclusive environment.

Our target for Inclusive Leadership Training in 2022/23 was to achieve a completion rate of 75 per cent. We achieved a 73 per cent completion rate, just below the target, with 417 of the 572 leaders completing the course.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
4.d Operations Training Hours[1] [Average hours per Operations technical employee incremental to safety training]	39	35	49

Data source: Results are measured by tracking employee time in BC Hydro SAP system.
[1]PM 4.d targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 30 and 30, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Operations Training Hours is a measure of the hours of annual training completed by Operations technical employees. It is important for Operations employees to complete technical and leadership training, in addition to mandatory safety and regulatory training to maintain the skills required to work safely and efficiently and maintain system reliability.

BC Hydro exceeded its 2022/23 target with a result of 49 average hours of annual training completed by Operations technical employees. This result was mainly due to the onboarding of new employees and existing employees receiving training that was delayed due to the COVID-19 pandemic. Training will return to 2021/22 levels beginning in 2023/24.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
4.e Mandatory Reliability Standards Non-Compliance Reduction (%) [Non-compliance reduction compared to 2020/2021]	57	60	80

Data source: The data source for all reliability standards compliance performance metrics and incidents is based on information provided by BC Hydro business groups. Reliability Standards incidents are reported to the Reliability Standards Assurance team and investigated to determine if the incident is reportable to the Western Electricity Coordinating Council.
[1]PM 4.e targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 70 and 80, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Mandatory Reliability Standards Non-Compliance is a measure that shows the percentage of decrease in non-compliance incidents reportable to the Western Electricity Coordinating Council relative to 2020/21. This measure indicates BC Hydro’s continual improvement in managing reliability standards compliance risks.

BC Hydro exceeded its 2022/23 target for reduction in Mandatory Reliability Standards non-compliances, with a result of an 80 per cent non-compliance reduction since 2020/21, compared to a target of 60 per cent. With increased complexity and scope of the Mandatory Reliability Standards, achieving the non-compliance reduction targets will require ongoing effort in future years. Throughout the year, BC Hydro strengthened its Mandatory Reliability Standards program by implementing improvements in processes, controls and training to address non-compliances experienced in the past, adding additional resources and making ongoing program investments.

Goal 5: Advance Reconciliation with Indigenous Peoples

Objective 5.1: BC Hydro will advance reconciliation by continuing to invest in and build mutually beneficial and stronger relationships with Indigenous communities.

Advancing reconciliation is a long-standing priority for BC Hydro. Mutually beneficial relationships with Indigenous Nations are critical to operating and growing our system of clean electricity.

Key results

- Renewed one and extended two existing Relationship Agreements and reached an additional Relationship Agreement with a First Nation community whose members requested an individual level relationship with BC Hydro.
- Drafted an UNDRIP Implementation Plan, in consultation with First Nations to incorporate the principles of UNDRIP into our business for the benefit of First Nations and Indigenous Peoples.
- Awarded $1.162 billion since 2024 in direct contracts to Indigenous-designated businesses, exceeding the 2022/23 target of $880 million.
- Developed a Non-Integrated Areas Strategy with a focus on Diesel Reduction and engaged with Indigenous communities as part of the CleanBC Plan. BC Hydro also worked with Nations to identify more clean energy project opportunities.

Summary of progress made in 2022/23

Operating, maintaining and expanding BC Hydro's extensive electricity system impacts a significant number of Indigenous communities across the province. This year, BC Hydro worked with Indigenous Nations to advance reconciliation and to pursue meaningful, long-term relationships that better reflect Indigenous interests. In 2022/23, we worked to renew three relationship agreements that were set to expire. BC Hydro renewed one five-year Relationship Agreement and extended two other agreements to allow additional time for negotiations, which remain in the final stages. In addition, a Relationship Agreement was reached with a First Nation community with whom we had previously had a multi-community, Nation-level agreement but whose members expressed a preference for an individual level relationship with BC Hydro.

Pursuant to the historic passing of the *Declaration on the Rights of Indigenous Peoples Act* in November 2019, BC Hydro worked to implement the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and drafted an UNDRIP Implementation Plan, in consultation with First Nations in 2022/23. The plan outlines the actions BC Hydro is taking or will take to incorporate the principles of UNDRIP into our business for the benefit of First Nations and Indigenous Peoples, expanding on the significant relationship building that has taken place. In 2022/23, BC Hydro began to engage with First Nations on the draft UNDRIP Implementation Plan and to update our 2015 Statement of Indigenous Principles, which guides our work with Indigenous peoples in B.C. We also worked to implement the Calls to Action of the Truth and Reconciliation Commission and the Draft Principles that Guide the Province of B.C.'s Relationship with Indigenous Peoples into our business.

BC Hydro continued to seek, develop and sustain positive long-term relationships and to better understand Indigenous interests so that these priorities were recognized in our capital projects, programs and operations activities. Seven Indigenous university graduates joined our Indigenous Professionals In Development Program for six-month rotations across various divisions to gain on-the-job experience and apply for BC Hydro roles. This year, BC Hydro hired 29 Indigenous people into full-time, part-time regular and temporary positions; of these, 12 individuals were hired into full-time positions throughout the company. In addition, 37 Indigenous students from across the province were awarded scholarships and bursaries to advance their education, totalling approximately $179,000.

Performance measure(s) and related discussion

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
5.a Indigenous Procurement ($ million)[1] [Cumulative total beginning in 2014/15]	914	880	1,162

Data source: The data source is a report generated by BC Hydro's Supply Chain team that includes the value of direct and indirect procurement, contracts issued and contract spend.
[1]PM 5.a targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 930 million and 970 million, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Indigenous Procurement is a measure of the total cumulative dollar value of procurement at BC Hydro awarded to Indigenous Nations beginning in 2014/15. Consistent with BC Hydro's Indigenous Contract and Procurement policy this measure demonstrates BC Hydro's support for the long-term economic interests of Indigenous peoples in British Columbia by committing to directed procurement opportunities. This commitment supports our Relationship Agreements, impact benefit agreements and other arrangements with Indigenous groups.

The Indigenous Procurement performance measure represents opportunities for Indigenous Nations to share in the benefits of the work that BC Hydro does to build, operate and maintain the system. Since 2014, BC Hydro has awarded $1.162 billion in direct contracts to Indigenous-designated businesses, exceeding the 2022/23 target of $880 million. As a result future years' targets have been adjusted upward. Additional economic and community benefits flowing from direct and indirect Indigenous procurements are not captured by this metric.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
5.b Indigenous Employment[1] (%)	4.1	4.3	4.0

Data source: Employees respond to an optional survey request to self-identify their ethnicity when they join BC Hydro. The survey is administered by BC Stats on behalf of BC Hydro, and BC Stats maintains our diversity database. Data on our workforce diversity and available workforce are calculated and stored with BC Stats.
[1]PM 5.b targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 4.6 and 4.9, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Increasing Indigenous representation at BC Hydro supports reconciliation by ensuring the inclusion of Indigenous voices and perspectives in our work. Increasing Indigenous representation is supported by our inclusion, diversity, equity and accessibility strategy and the implementation of UNDRIP. BC Hydro gained 22 Indigenous employees since the beginning of 2022/23, bringing the total of self-identified Indigenous employees in our workforce to 4 per cent, which was below target but higher than the available B.C. workforce of 3.6 per cent in the occupations that we hire.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
5.c Indigenous Awareness Training at BC Hydro (% complete)[1]	53	55	74

Data source: Course completion is measured by tracking the course participation in INDIG-101 and/or INDIG-201.
[1]PM 5.c targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as 63 and 71, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

The Indigenous Awareness Training measure assesses progress towards having 80 per cent of all BC Hydro employees completing INDIG-101 and/or 201 training over a five-year period starting in 2021/22. Cultural awareness training provides information and tools to our employees to advance reconciliation and support Indigenous employee retention.

BC Hydro exceeded its 2022/23 target of 55 per cent with a result of 74 per cent. The increased participation rate was achieved primarily through proactive communications with employees to raise awareness of the courses.

Performance Measure	2021/22 Actual	2022/23 Target	2022/23 Actual
5.d Progressive Aboriginal Relations Certificate[1]	Gold	Gold	Gold

Data source: BC Hydro prepares a submission once every three years outlining our approach, programs and results, examples and testimonials, and other supporting information in each of the defined categories. This involves answering 59 questions outlined by the PAR certification program overseen by the Canadian Council for Aboriginal Business. The PAR certification is the only program of its type in Canada.
[1]PM 5.d targets for 2023/24 and 2024/25 were stated in the 2022/23 Service Plan as Gold and Gold, respectively. For forward-looking planning information, including current targets for 2023/24 – 2025/26, please see the latest Service Plan on the BC Budget website.

Progressive Aboriginal Relations (PAR) Designation is a certification from the Canadian Council for Aboriginal Business designed to help Canadian businesses benchmark, improve and signal their commitment to progressive relationships with Indigenous communities, businesses and people. Certification is for a three-year period.

In 2021/22, BC Hydro obtained our fourth consecutive Gold certification under the Canadian Council for Aboriginal Business's Progressive Aboriginal Relations program. This demonstrates BC Hydro's commitment to implementing leading Indigenous Relations practices across the areas of leadership, community relationships, business development and employment. BC Hydro is one of 18 companies in Canada to achieve Gold status, and one of only two utilities at the Gold level.

Financial Report

For the auditor's report and audited financial statements, see Appendix C. These documents can also be found on BC Hydro's 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, 2023 and should be read in conjunction with the 2022/23 Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2023 and 2022.

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

- The net income for the year ended March 31, 2023 was $360 million, $308 million lower than the prior fiscal year primarily due to cost-of-living credits issued to customers.

- In November 2022, government issued a directive to the British Columbia Utilities Commission (BCUC) which required the BCUC to issue a directive to BC Hydro to provide cost-of-living credits to residential and commercial customers. This resulted in a $315 million decrease in revenues and a corresponding decrease in net income. Please refer to the Rate Regulation section of the MD&A for more details regarding the issuance of customer credits.

- On April 21, 2023, the BCUC issued a preliminary decision on BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (F2023 – F2025 RRA) and issued a series of compliance directives. The net impact of these directives was an increase to net income of $1 million and a revised bill decrease for fiscal 2023 of 1.32 per cent instead of the BCUC-approved interim bill decrease of 1.38 per cent. Please refer to the Rate Regulation section of the MD&A for more details regarding the decision on the F2023 – F2025 RRA.

- Domestic sales volumes for the year ended March 31, 2023 were 807 GWh (or 2 per cent) higher than the prior fiscal year. The higher sales volumes were primarily due to the economy gradually recovering from the impacts of COVID-19 and weather.

- The net regulatory asset balance (i.e., amount recoverable from ratepayers) as at March 31, 2023 was $1.47 billion, $1.44 billion (or 50%) lower than the prior fiscal year.

- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2023 were $3.92 billion, a $444 million increase over the prior fiscal year. The increase was primarily due to higher Site C expenditures.

Consolidated Results of Operations

for the years ended March 31 ($ in millions)		**2023**		2022		Change
Total Revenues	**$**	**8,027**	$	7,591	$	436
Net Income	**$**	**360**	$	668	$	(308)
Capital Expenditures	**$**	**3,919**	$	3,475	$	444
GWh Sold (Domestic)		**54,259**		53,452		807

as at March 31 ($ in millions)		**2023**		2022		Change
Total Assets and Regulatory Balances	**$**	**45,786**	$	42,734	$	3,052
Shareholder's Equity	**$**	**7,356**	$	7,046	$	310
Retained Earnings	**$**	**7,354**	$	6,994	$	360
Debt to Equity		**78:22**		78:22		n/a
Number of Domestic Customer Accounts		**2,188,693**		2,156,202		32,491

Revenues

For the year ended March 31, 2023, total revenues of $8.03 billion, were $436 million (or 6 per cent) higher than the prior fiscal year. The increase was due to higher trade revenues of $751 million, partially offset by lower domestic revenues of $315 million.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [1]	
for the years ended March 31	**2023**	2022	**2023**	2022	**2023**	2022
Revenues						
Residential	**$ 2,146**	$ 2,342	**19,547**	19,440	**$ 109.79**	$ 120.47
Light industrial and commercial	**1,840**	1,952	**19,247**	19,029	**95.60**	102.58
Large industrial	**848**	854	**13,437**	13,312	**63.11**	64.15
Other sales	**470**	471	**2,028**	1,671	**-**	-
Domestic Revenues	**5,304**	5,619	**54,259**	53,452	**97.75**	105.12
Trade Revenues	**2,723**	1,972	**32,762**	31,267	**119.56**	68.71
Revenues	**$ 8,027**	$ 7,591	**87,021**	84,719	**$ 92.24**	$ 89.60

[1] The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions.

Domestic Revenues

For the year ended March 31, 2023, domestic revenues were $5.30 billion, $315 million (or 6 per cent) lower than the prior fiscal year. The decrease was primarily due to $315 million of credits issued to residential and commercial customers after the announcement on cost-of-living credits by the Government in November 2022. The decrease was also due to lower average rates that reflect the 1.38 per cent bill decrease approved on an interim basis by the BCUC and the impact of Order G-91-23 from the BCUC on the BC Hydro's F2023 – F2025 RRA, partially offset by an increase in domestic sales volumes.

Domestic sales volumes were 807 GWh (or 2 per cent) higher than the prior fiscal year. The increase was due to higher Other sales primarily due to higher sales volumes to a third party, higher Light Industrial and Commercial sales volumes primarily due to increased business activity as the economy recovered from the impacts of COVID-19, as well as higher Residential sales volumes as a result of colder than prior year temperatures in some months.

Trade Revenues

For the year ended March 31, 2023, trade revenues were $2.72 billion, $751 million (or 38 percent) higher than the same period in the prior fiscal year. The increase was primarily driven by higher average sale prices for the period.

Operating Expenses

For the year ended March 31, 2023, total operating expenses of $6.01 billion were $215 million (or 4 per cent) higher than the prior fiscal year. The increase was primarily due to higher energy costs of $121 million, higher materials and external services of $85 million, higher personnel costs of $26 million, and higher grants and taxes of $10 million. This was partially offset by lower amortization and depreciation of $27 million.

Energy Costs

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals, transmission and other 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, energy demand, and environmental and social impacts.

Energy costs for the year ended March 31, 2023 were $3.12 billion, $121 million (or 4 per cent) higher than the prior fiscal year. The increase was primarily due to higher trade energy costs of $385 million and lower domestic energy costs of $264 million.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31	**2023**	2022	**2023**	2022	**2023**	2022
Energy Costs						
Water rental payments (hydro generation)[1]	**$ 358**	$ 345	**45,311**	47,072	**$ 7.90**	$ 7.33
Purchases from Independent Power Producers	**1,421**	1,522	**15,409**	16,824	**92.22**	90.47
Gas and transportation for thermal generation	**6**	3	-	-	-	-
Transmission charges and other expenses	**57**	49	**121**	119	**-**	-
Non-Treaty storage and co-ordination agreements	**(170)**	17	**-**	-	**-**	-
Domestic Energy Costs	**1,672**	1,936	**60,841**	64,015	**27.48**	30.24
Trade Energy Costs	**1,451**	1,066	**31,679**	26,177	**72.78**	45.45
Energy Costs	**$ 3,123**	$ 3,002	**92,520**	90,192	**$ 33.75**	$ 33.28

[1]Water rental payments are based on the previous calendar year's generation volumes. The volumes are actual hydro generation during the period. The $ per MWh is a simple average calculation and does not reflect actual water rental rates during the period.
[2]The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions.

Domestic Energy Costs

Domestic energy costs for the year ended March 31, 2023 were $1.67 billion, $264 million (or 14 per cent) lower than the prior fiscal year. The decrease in costs was primarily due to lower Non-Treaty Storage and Co-ordination agreements costs due to more net water releases at higher prices compared to the prior year. In addition, there were lower purchases from Independent Power Producers (IPPs) due to lower deliveries from hydro IPPs and more outages in the current year, partially offset by higher energy deliveries from several IPPs due to changes to their operations in the current year that increased the amount of energy available for sale to BC Hydro.

Trade Energy Costs

Trade energy costs for the year ended March 31, 2023 were $1.45 billion, $385 million (or 36 percent) higher than the same period in the prior fiscal year. The increase was primarily driven by higher average purchase prices for the period.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system for the year ended March 31, 2023 were below average and lower than the prior fiscal year. The system initially saw above average inflows in the Columbia system at the start of fiscal year, primarily from an above average snowpack. It was followed, however, by dry conditions and below average inflows across the province in all months from July 2022 to March 2023, except for February 2023.

System energy storage is tracking below the ten-year historic average due to below average inflows in the fiscal year. System energy storage at March 31, 2023 was lower than at March 31, 2022.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2023 were $762 million, $26 million (or 4 per cent) higher than the prior fiscal year primarily due higher labour costs including compensation increases commensurate to the public sector mandate, partially offset by lower current service pension costs attributed to higher pension discount rates which are based on rates at the beginning of the fiscal year.

Materials and External Services

Materials and External Services primarily includes materials, supplies, and contractor fees. Expenditures on materials and external services for the year ended March 31, 2023 were $757 million, $85 million (or 13 per cent) higher than the prior fiscal year primarily due to higher costs from various areas across the organization, which included higher costs for cyber security, cloud computing and maintenance.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, right-of-use assets, and amortization of intangible assets. For the year ended March 31, 2023, amortization and depreciation expense was $1.05 billion, $27 million (or 3 per cent) lower than the prior fiscal year primarily due to a change in the estimated useful lives of BC Hydro's property, plant, and equipment based on the recommendations from a depreciation study completed in the first quarter of the prior fiscal year, which resulted in an one time charge in the prior year due to prospective application.

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, 2023 were $296 million, which is comparable to the $286 million in the prior fiscal year.

Other Costs, Net of Recoveries

Other costs, net of recoveries primarily includes gains and losses on the disposal of assets, certain cost recoveries related to operating costs, and dismantling costs. For the year ended March 31, 2023, other costs net of recoveries were $105 million, which is comparable to the $97 million in the prior year.

Capitalized Costs

Capitalized costs consist of costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the year ended March 31, 2023 were $86 million, which is comparable to the $78 million in the prior fiscal year.

Finance Charges

Finance charges for the year ended March 31, 2023 were $496 million, a decrease of $25 million (or 5 per cent) compared to the same period in the prior fiscal year. The decrease was primarily due to higher interest capitalized during construction, and gains on future debt hedges used to economically hedge the interest rates on future debt issuances. The decrease was partially offset by higher interest rates on short-term borrowings, higher foreign exchange losses, and higher volume of long-term debt.

Regulatory Transfers

In accordance with 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 North American utility industries. 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 to future periods differences between forecast and actual costs or revenues. 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)		**2023**		2022
Cost of Energy Variance Accounts				
Heritage Deferral Account	**$**	**(121)**	$	38
Non-Heritage Deferral Account		**51**		(28)
Trade Income Deferral Account		**(747)**		(264)
Load Variance		**(60)**		(79)
Biomass Energy Program Variance		**(40)**		(26)
Other		**(22)**		(31)
		(939)		(390)
Other Cash Variance Accounts				
Remediation		**50**		45
Inflationary Pressures		**(57)**		-
Other		**3**		81
		(4)		126
Non-Cash Variance Accounts				
Non-Current Pension Costs		**(155)**		(668)
Debt Management		**(201)**		(153)
Other		**(16)**		(24)
		(372)		(845)
Benefit Matching Accounts				
Demand-Side Management		**101**		94
First Nations Costs		**15**		15
Site C		**6**		3
CIA Amortization		**(5)**		(5)
Other		**12**		-
		129		107
Non-Cash Provisions				
Environmental Provisions		**(35)**		(46)
First Nations Provisions		**34**		-
		(1)		(46)
Amortization of regulatory accounts		**(246)**		(330)
Interest on regulatory accounts		**(11)**		12
Net decrease in regulatory accounts	**$**	**(1,444)**	$	(1,366)

For the year ended March 31, 2023, there was a net reduction of $1.44 billion (or 50%) to the Company's regulatory accounts compared to a net reduction of $1.37 billion in the prior fiscal year. The net regulatory asset balance as at March 31, 2023 was $1.47 billion compared to $2.91 billion as at March 31, 2022.

Net reductions to the regulatory accounts during the year ended March 31 2023 included a $939 million net reduction to the Cost of Energy Variance Accounts primarily due to higher trade income than planned, a $246 million reduction due to Amortization, a $201 million reduction to the Debt Management Regulatory Account primarily due to a net increase in the fair value of interest rate hedges resulting from an increase in forward interest rates, a $155 million reduction to the Non-Current Pension Costs Account primarily due to actuarial gains as a result of an increase in the discount rate used to measure the pension liability partially offset by an actuarial loss on pension plan assets as a result of a decrease in the rate of return on pension plan assets, and a net decrease of $4 million in the remaining regulatory accounts. These reductions were partially offset by a $101 million increase in Demand-Side Management expenditures.

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2023**	2022
Cost of Energy Variance Accounts		
Heritage Deferral Account	**$ (32)**	$ 105
Non-Heritage Deferral Account	**(110)**	(185)
Trade Income Deferral Account	**(1,190)**	(504)
Load Variance	**(33)**	33
Biomass Energy Program Variance	**(75)**	(40)
Other	**(48)**	(30)
	(1,488)	(621)
Other Cash Variance Accounts		
Remediation	**(24)**	(41)
Inflationary Pressures	**(58)**	-
Other	**145**	180
	63	139
Non-Cash Variance Accounts		
Non-Current Pension Costs	**(854)**	(669)
Debt Management	**67**	286
Other	**(26)**	(18)
	(813)	(401)
Benefit Matching Accounts		
Demand-Side Management	**858**	868
First Nations Costs	**19**	37
Site C	**566**	542
CIA Amortization	**63**	68
Smart Metering & Infrastructure	**130**	151
Other	**12**	-
	1,648	1,666
Non-Cash Provisions		
Environmental Provisions	**240**	275
First Nations Provisions	**466**	432
	706	707
IFRS Transition Accounts		
IFRS Pension	**344**	382
IFRS Property, Plant & Equipment	**1,007**	1,039
	1,351	1,421
Net Regulatory Asset	**$ 1,467**	$ 2,911

Figures in parentheses are regulatory liabilities (owing to ratepayers) and positive numbers are assets (recoverable from ratepayers).

BC Hydro has regulatory mechanisms to collect 33 of 36 regulatory accounts with balances or in use at March 31, 2023 in rates over various periods.

Comparison with Service Plan

The *Budget Transparency and Accountability Act* requires that BC Hydro file a service plan each year. BC Hydro's 2022/23-2024/25 Service Plan (Service Plan) was filed in February 2022 with forecast net income for 2022/23 of $712 million.

The table below provides an overview of BC Hydro's 2022/23 financial results, relative to its Service Plan.

(in millions)	Actual	Service Plan[2]	Variance to Service Plan
For the year ended March 31,	**2023**	**2023**	
Revenues			
Domestic	$ 5,304	$ 5,571	$ (267)
Trade	2,723	1,602	1,121
	8,027	7,173	854
Expenses			
Operating Costs			
Cost of energy	3,123	2,912	(211)
Other operating expenses			
Personnel expenses, materials and external services [1]	1,406	1,397	(9)
Amortization	1,052	1,036	(16)
Grants and taxes	296	292	(4)
Other	132	105	(27)
Finance charges	496	577	81
	6,505	6,318	(186)
Net Income Before Movement in Regulatory Balances	1,522	855	668
Net movement in regulatory balances	(1,162)	(143)	(1,019)
Net Income	$ 360	$ 712	$ (352)

[1] These amounts are net of capitalized costs and recoveries.

[2] Column may not add due to rounding.

Net income for 2022/23 was $360 million, compared to forecast net income of $712 million in the Service Plan filed in February 2022. 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. The lower net income was primarily due to the $315 million of credits issued to residential and commercial customers after the announcement on cost-of-living credits by the Government in November 2022, and also due to variances in certain operating costs that were above planned amounts, and which were not subject to deferral to regulatory accounts.

Liquidity and Capital Resources

Cash flow provided by operating activities for the year ended March 31, 2023 was $2.52 billion, compared to $2.42 billion in the prior fiscal year. The increase was mainly due to higher trade income partially offset by lower domestic revenues due to the cost-of-living credits issued and lower cash from changes in working capital.

The long-term debt balance net of sinking funds as at March 31, 2023 was $26.78 billion compared to $25.74 billion as at March 31, 2022. The increase was mainly a result of an increase in net long-term bond issuances (net of redemptions) for net proceeds of $998 million. The increase was primarily to fund capital expenditures and to manage working capital.

Capital Expenditures

Capital expenditures 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)		**2023**		2022
Transmission lines and substations replacements and expansion	**$**	**504**	$	436
Generation replacements and expansion		**334**		351
Distribution system improvements and expansion		**633**		572
General, including technology, vehicles and buildings		**261**		192
Site C Project		**2,187**		1,924
Total Capital Expenditures[1]	**$**	**3,919**	$	3,475

[1]Total capital expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Statements of Cash Flows because the expenditures above include accruals.

The increase in capital expenditures of $444 million for the year ended March 31, 2023 compared to the same period in the prior fiscal year was primarily due to higher Site C Project expenditures.

Transmission lines and substation replacements and expansion included capital expenditures on transmission overhead lines, cables, substations, telecommunication systems, and transmission power equipment. Key capital expenditures included the following projects/programs: Transmission Wood Structure and Framing Replacements, Capilano Substation Upgrade, Various Sites –NERC (North American Electric Reliability Corporation) CIP (Critical Infrastructure Protection) Implementation project for cyber assets, 5L063 Telkwa Relocation, Treaty Creek Terminal – Transmission Load Interconnection (KSM), and Sperling Substation (SPG) Metalclad Switchgear Replacement.

Generation replacements and expansion included capital expenditures 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 expenditures included the following projects: John Hart Dam Seismic Upgrade, Bridge River 1 – Penstock Concrete Foundation Refurbishment, Bridge River 2 – Strip and Recoat Penstock 2 Interior, G.M. Shrum Upgrade Heating Ventilation Air Conditioning (HVAC) System, Mica Upgrade HVAC System, and Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior).

Distribution system improvements and expansion included capital expenditures on customer driven work, end of life asset replacements, and system expansion and improvements.

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

Site C incurred capital expenditures across the project, primarily for work areas such as generating station and spillways, main civil works, turbines and generators, right bank foundation enhancements, highway realignment and for worker accommodations, project management and support services and interest during construction.

Rate Regulation

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and earn an annual rate of return.

Regulatory Applications

On June 27, 2022, the Government of B.C. issued a Direction to the BCUC Respecting Load Attraction and Low-Carbon Electrification (B.C. Reg 156/2022, Order in Council No. 355) under section 3 of the Utilities Commission Act. Order in Council No. 355 prescribes requirements respecting the recovery of costs for low carbon electrification and for attracting additional customer load.

On November 18, 2022, the Government of B.C. issued a Direction to the BCUC Respecting Residential and Commercial Customer Account Credits (B.C. Reg 163/2021, Order in Council No. 571) under section 3 of the Utilities Commission Act. On November 28, 2022, the BCUC issued Order No. G-341-22 as directed. The Order authorized BC Hydro to establish a Customer Credit Regulatory Account and Inflationary Pressures Regulatory Account and transfer $320 million and $74 million, respectively, from the Trade Income Deferral Account to these new accounts. In addition, it authorized BC Hydro to transfer $6 million from the Trade Income Deferral Account to the Customer Crisis Fund Regulatory Account. It also required BC Hydro to provide account credits to commercial and residential customers, defer the amount of the customer credits issued to the Customer Credit Regulatory Account and allows BC Hydro to defer specified inflationary pressure amounts to the Inflationary Pressures Regulatory Account.

On March 31, 2023, BC Hydro submitted an application to the BCUC seeking approval to reinstate a $320 million regulatory liability to the Trade Income Deferral Account. The effect of the reinstatement of the $320 million regulatory liability is that the customer credits issued in accordance with the Direction and BCUC Order No. G-341-22 (and discussed in the preceding paragraph) will have been funded through BC Hydro's operations (i.e., by a reduction in BC Hydro's actual fiscal 2023 net income) and not by ratepayers. Customers will retain the credits they received and there will be no bill adjustments because of the application. The BCUC review of BC Hydro's application to reinstate the $320 million regulatory liability in the Trade Income Deferral Account is currently underway and the BCUC will issue its decision in due course. The financial impact of the transfer request has been incorporated in the financial statements in accordance with the Company's rate regulation accounting policy, whereby BC Hydro recognizes the impacts of requests in advance of a final decision by the BCUC based on management's estimate on the probability of acceptance.

On April 21, 2023, the BCUC issued a preliminary decision on BC Hydro's F2023 – F2025 RRA and issued a series of compliance directives. The net impact of these directives was an increase to net income of $1 million and a revised estimated bill decrease for fiscal 2023 of 1.32 per cent. This is a 0.06 per cent change in the bill impact compared to the 1.38 per cent interim bill decrease approved by the BCUC for fiscal 2023 that BC Hydro has been charging customers since April 1, 2022. This resulted in a $4 million increase in domestic revenue for the year ended March 31, 2023 and this impact has been incorporated in the financial statements.

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.

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. Regulatory accounts assist in matching costs and benefits for different generations of customers and to defer for future recovery 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 2023 – Fiscal 2025 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, domestic and trade energy cost, and finance charges. These are influenced by several elements, which are generally categorized into the following six factors:

- Hydro generation;
- Customer demand;
- Electricity/gas trade margins;
- Deliveries from electricity purchase agreement contracts;
- Interest rates; and
- Discount rates – Post Employment Benefit Plans.

Neither a high nor a low value of any of these individual factors is intrinsically positive or negative for BC Hydro's financial results. It is the specific combination of these factors in any given year which has an impact.

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.

The Site C Project continues to manage significant potential risks including the availability of skilled workers, commercial negotiations with contractors, potential impact of communicable diseases, design changes due to unknown field conditions, and potential inflationary related risks. The Site C Project Assurance Board (which is comprised of independent members and some of the current BC Hydro board members) is tasked with ensuring that the Site C Project is completed on time and on budget, and that risks are appropriately identified, managed and reported on an ongoing basis. As of March 31, 2023, the total Project forecast remains at the $16 billion estimate and is expected to achieve the in-service date of 2025.

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 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 and future years.

The range of inflows, year to year, can significantly influence available generation: over 14,000 GWh (or approximately 25 per cent of current domestic demand) 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, 2023 were below average and lower than the prior fiscal year driven by dry conditions and below average inflows across the province in all months from July 2022 to March 2023, except for February 2023.

Customer Demand

Customer demand for electricity is generally forecast to increase in the long term as B.C.'s population and economy continue to grow. However, long term projections of customer load entail inherent uncertainty, particularly in B.C.'s resource sectors. 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. Other factors include the implementation of CleanBC initiatives and the adoption of BC Hydro's Electrification Plan. 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, and the rate of uptake in Demand-Side Management programs.

There can also be short-term fluctuations in customer load due to timing of new large customer facility start-up 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.

Domestic load volumes for the year ended March 31, 2023, were approximately 2 per cent higher compared to the prior fiscal year. This increase was primarily due higher sales to one utility and the gradual recovery of the economy from the COVID-19 pandemic, as well as colder temperatures than in the prior year in some months. Recent economic concerns related to inflation, increased interest rates, and market conditions for large industrial customers may continue to impact electricity demand.

Electricity/Gas Trade Margins

Electricity and gas trade margins are impacted by electricity and gas prices. Electricity and gas prices, themselves, are variable and a function of gas and electricity market fundamentals.

For the year ended March 31, 2023, electricity and gas trade margins were higher than prior year due to higher average sale prices.

Deliveries from Electricity Purchase Agreement Contracts (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 average energy cost 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, 2023, overall energy delivered from EPAs was lower than forecast. Although biomass and non-storage hydro projects delivered less energy than expected, the lower than forecast deliveries from these projects were partially offset by higher than forecast deliveries from storage hydro generation projects.

Interest Rates

A portion of BC Hydro's existing debt will be impacted by changes to interest rates for debt with a remaining term to maturity of one year or less, 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, 2023, approximately 11 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, 2023, BC Hydro had interest rate hedges in place with an aggregate notional principal of $2.88 billion, hedging a portion of its forecast long-term debt issuances out to and including 2026/27.

Discount Rates – Post-Employment Benefit Plans Current Service Costs

Discount rates are one of the actuarial assumptions used to determine post-employment benefit plan current service costs, which are sensitive to changes in discount rates. An increase in discount rates will decrease current service costs and a decrease in discount rates will increase current service costs.

The discount rates for the year ended March 31, 2023 were higher than the prior year due to higher AA Canadian corporate bond yields.

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 2023 forecast net income for 2023/24 at $712 million which is consistent with the amount required by Order in Council No. 123. In addition, net income for the period 2024/25 – 2025/26 is forecast to be $712 million annually.

The Company's earnings 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. The forecast for 2023/24 assumes average water inflows (100 per cent of average), domestic sales of 55,636 GWh, average market energy prices of US $83.41/MWh, short-term interest rates of 3.86 per cent, and a Canadian to US dollar exchange rate of US $0.7645.

With recent increases in inflation and interest rates, economic concerns have grown. A potential recession could adversely impact BC Hydro's future performance if it were to cause a decrease in customer load, volatility in electricity/gas trade margins, interest rate volatility, difficulty accessing debt, project delays and project cost escalations. In addition, the on-going conflict in Ukraine and other geopolitical factors have caused negative disruptions to supply chains which are resulting in project delays and project cost escalations, with the risk of further delays and cost escalations.

These economic concerns limit the ability to predict the ultimate adverse impact of the economy on BC Hydro's performance, financial condition, results of operations and cash flows.

Earnings Sensitivity

The following table shows the estimated effect on net income of changes in some key variables, before regulatory account transfers. The analysis is based on business conditions and generation volumes forecast for 2023/24. Each separate item in the sensitivity analysis assumes the others are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitude of changes.

The volatility between BC Hydro's plan and actual results are mostly mitigated through the use of BCUC-approved regulatory accounts.

Factor	Change	Approximate change in 2023/24 earnings before regulatory account transfers (in millions)	5 year high	5 year low	2022/23
Hydro generation [1]	+/- 1%	$40	49,796 GWh	40,382 GWh	46,138 GWh
Customer demand [2]	+/- 1%	$5	54,260GWh	51,140 GWh	54,260 GWh
Electricity/gas trade margins [3]	+/- 1%	$4	$1,272	$248	$1,272
Purchases from EPAs [4]	+/- 1%	$2	16,824 GWh	14,248 GWh	15,409 GWh
Interest rates - variable debt [5]	+/- 100 basis points	$40	3.83%	0.53%	3.83%
Interest rates – hedges of future debt issuances [6]	+/- 100 basis points	+$325/-$400	10-yr 3.50% 30-yr 3.43%	10-yr 1.22% 30-yr 1.64%	10-yr 3.50% 30-yr 3.43%
Discount rates - Post-employment benefit plan current service costs [7]	+/- 100 basis points	+$17/-$23	4.38%	3.33%	4.38%

[1] Assumes a change in hydro generation is offset by a corresponding change in system imports or exports.

[2] Assumes a percentage change is applied equally to all customer classes. Assumes a change in customer load is offset by a corresponding change in system imports or exports.

[3] Trade revenues less trade energy costs (in millions).

[4] Assumes a change in purchases from EPAs is offset by a corresponding change in system imports or exports.

[5] Interest rates are the annual daily average Canadian short-term interest rates (3-month Canadian Dollar Offered Rate). The values in the 5-year high and low columns are the high and low of the annual averages and not the high and low of all daily rates during the 5-year period.

[6] Relates to unrealized gains/(losses) on interest rate hedges of future debt issuances. Note that hedging gains and losses serve to offset variation in annual interest rates costs when amortized through the Debt Management Regulatory Account (DMRA). Sensitivity is based on notional value of hedges outstanding and market interest rates as of March 31, 2023. Interest rates are the annual daily average 10-year and 30-year spot swap rates. The values in the 5-year high and low columns are the high and low of the annual average rates and not the high and low of all daily rates during the 5-year period. Spot swap rates are used as an indicative proxy for the purposes of this table. Actual DMRA interest rate sensitivity is dependent on the market forward bond yields and market forward swaps rates specific to each future debt hedge outstanding at a given point in time.

[7] Discount rate based on the yields of AA Canadian Corporate bonds.

Capital Expenditures

BC Hydro has the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors.

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2023 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Projects Recently Put Into Service				
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. There was a heightened reliability and safety risk from continuing to operate these transformers in an underground powerhouse as they aged.	2022 In-Service	$75	$14	$89
Mount Lehman Substation Upgrade Project This project increased the firm capacity of the Mount Lehman Substation to address safety and asset health concerns at both the Clayburn and Sumas Way substations.	2023 In-Service	$53	$2	$55

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2023 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Ongoing				
G.M. Shrum (GMS) G1 to 10 Control System Upgrade This project will replace the controls equipment, provide full remote-control capability from the control center, and rectify deficiencies in the current system. The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of available spare parts and decreasing reliability. The controls are well beyond their expected life, which causes operating problems and increases the risk of damage to major equipment.	2023 Targeted In-Service	$69	$6	$75
5L063 Telkwa Project This project will increase the reliability and reduce the safety risks of the 500kV radial transmission line (5L063) that provides service for customers in Northwest British Columbia. A portion of the 5L063 line will be relocated away from the current area of unstable terrain.	2023 Targeted In-Service	$46	$20	$66
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment Project This project is to address safety and environmental risks by improving the reliability of the Coquitlam tunnel gates for control of water conveyance from the Coquitlam Reservoir to Buntzen Lake Reservoir.	2023 Targeted In-Service	$42	$25	$67

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2023 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Street Light Replacement Program The program will convert approximately 95,000 BC Hydro owned and maintained High Pressure Sodium and Mercury Vapour street lights to Light Emitting Diode (LED) street lights. This is required to meet federal polychlorinated biphenyl (PCB) environmental regulations by the end of 2025, manage increasing operations and maintenance costs, and better meet our customers' expectations. Lights have started to be converted and conversions will be completed in 2023.	2023 Targeted In-Service	$55	$20	$75
Various Sites – NERC Critical Infrastructure Protection Implementation Project for cyber assets This project is required to install equipment and establish processes, practices, and procedures to ensure that BC Hydro is compliant with the Critical Infrastructure Protection (CIP) CIP-003-7 and revised CIP-003-8 Mandatory Reliability Standards on all low impact Bulk Electric System Cyber Assets.	2023 Targeted In-Service	$40	$20	$60
Wahleach Refurbish Generator Project This project will improve the reliability of the generator at Wahleach Generating Facility, and its scope includes replacement of the stator and rotor poles, refurbishment of the remaining major components, and a combination of new, replacement, and refurbishment of the auxiliary components. The project also includes the installation of a new powerhouse crane and structural upgrades to the powerhouse building.	2023 Targeted In-Service	$44	$20	$64

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2023 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Capilano Substation Upgrade Project This project will address the existing asset health, reliability, safety, and environmental issues associated with the Capilano Substation, and to ensure that the capacity of the substation meets the long term area needs. The project will also introduce a 25kV source to enable 25kV voltage conversion and facilitate the execution of other future substation projects in the North Shore area.	2024 Targeted In-Service	$56	$31	$87
Mica Modernize Controls Project This project will address the reliability, maintainability, and operability of the Units 1-4 exciters, governors, unit controls and control room controls at the Mica Creek Generating Station.	2024 Targeted In-Service	$47	$9	$56
Vancouver Island Radio System Project This project will replace the end-of-life BC Hydro telecommunication system on Vancouver Island with a modernized system to improve reliability and increase communication capacity. Upgrades will be completed at 38 substations and microwave repeater sites and the project will also include installation of a new microwave radio link.	2024 Targeted In-Service	$41	$12	$53
Natal – 60-138 kV Switchyard Upgrade Project This project is to address reliability, regulatory and safety risks at the Natal substation as the 60-138kV switchyard equipment is at end of life and requires replacement.	2025 Targeted In-Service	$23	$61	$84

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2023 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Site C Project*** This project will construct a third dam and a hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. **Planned in-service date for all units.* ***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 with a project in-service date of calendar year 2025. BC Hydro continues to manage significant risks to the project and continues to work with the Project Assurance Board, Mr. Milburn, Ernst & Young Canada, and the Technical Advisory Board to manage these project risks.*	2025* Targeted In-Service	$11,020	$4,980	$16,000**
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.	2026 Targeted In-Service	$34	$42	$76

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2023 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
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, 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 $37 million.*	2026 Targeted In-Service	$27	$82	$109*
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.	2026 Targeted In-Service	$12	$142	$154
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.	2028 Targeted In-Service	$3	$58	$61
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	$18	$326	$344

Appendix A: Progress on Mandate Letter Priorities

The following is a summary of progress made on priorities as stated in the 2021/22 Mandate Letter from the Minister Responsible.

2021/22 Mandate Letter Priority	Status as of March 31, 2023

Provide leadership in advancing CleanBC's climate and economic development objectives, including electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, mining, oil and gas, and other sectors.	**Ongoing** • In December 2021, BC Hydro submitted the Integrated Resource Plan to the BC Utilities Commission that included electrification scenarios to show how BC Hydro will take advantage of our clean electricity to support the Province's CleanBC climate and economic objectives. • The 2021 Integrated Resource Plan outlined the process for identifying key changes in electricity demand and supply and evaluating whether a change in plan is needed. This is called the "signposts process." o Recognizing the unique planning challenges posed by the energy transition, BC Hydro implemented the signposts process to monitor for changes. o Signposts include updates to policies and legislation, deviations in actual customer demand, and changes in BC Hydro's existing and committed and planned resources. • BC Hydro is investing $260 million to advance its Electrification Plan between Fiscal 2022 (starting April 1, 2021) and Fiscal 2026 (ending March 31, 2026). The funding includes: o Approximately $190 million to promote fuel switching in homes and buildings, transportation and industries; and o More than $50 million to attract new load (electricity demand) from customers who have flexibility in which jurisdictions they operate. • Actions/investments to promote fuel switching include: o up to $26 million for building incentives, including up to $13 million in "top-up" offers for residential heat pumps (up to $3,000 per household) and new incentives for lower-income and commercial customers; o up to $30 million in incentives for the electrification of transportation (buses, ferries and fleets); o more than $60 million in incentives for industrial fuel switching; o public campaigns to increase public awareness of heat pumps and electric vehicles; and o continued support for delivery of existing CleanBC programs

	• Actions/investments to attract new industrial customers include: o up to $25 million in incentives and study funding for new customers; o up to $20 million in incentives and study funding to support the production of hydrogen; o site development strategy to help connect customers at sites with existing electrical infrastructure; and o public awareness strategy to promote BC Hydro's clean electricity advantage. • Other actions/investments in the Electrification Plan include: o supporting the residential supply chain sector for heat pump technologies to help transform the market for residential space and water heating; o ensuring adequate resources to support connecting customers in the timelines required; o improvements to BC Hydro's interconnections process; o supporting actions that complement government efforts to drive changes to policies, codes and standards.
Keep electricity affordable by ensuring that rates do not increase above inflation, on a cumulative basis, over the next decade.	**Ongoing** BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, requested an average annual bill increase of only 1.1 per cent – below the rate of forecasted provincial rate of inflation over the three-year period. This application reflected our efforts to continue to deliver safe and reliable power, while keeping electricity affordable for our customers.
Continue delivering affordability measures that support BC's Poverty Reduction Strategy, including demand-side management programs targeted to low-income customers, in a manner consistent with new and emerging CleanBC policies	**Ongoing** • In 2022/23, the Province and BC Hydro worked together to provide a "cost-of-living bill credit", to eligible customers. o Approximately 1.9 million residential customers received a one-time bill credit of $100, which is the equivalent of approximately one month of electricity charges for an average residential customer living in a detached home, or more than

	two months for an average customer living in an apartment. o Bill credits for commercial customers were distributed on a proportional basis, based on the customers' average electricity consumption and bills from October 1, 2021 through September 30, 2022. • In 2022/23, BC Hydro provided approximately 3,000 Customer Crisis Fund grants to customers facing emergency financial situations and disconnection with financial assistance of up to $600 to pay their bill. • As of Fiscal 2023, BC Hydro's Low Income conservation program has delivered approximately $6.5 million in annual electricity cost savings to customers to address energy affordability challenges. • Close to 27,000 customers have participated in the Energy Conservation Assistance program, including more than 4,000 homes in more than 100 Indigenous communities since the launch of the offer in 2009 and up to the end of Fiscal 2022. • As of the end of Fiscal 2022, more than 173,000 low-income homes have received Energy Saving Kits since the program launched in April 2008. • BC Hydro does not disconnect residential customers for non-payment during periods of extreme temperature. This includes a complete moratorium on non-payment disconnections in the North Interior and South Interior from November to March. In response to extreme temperatures in summer 2021, BC Hydro implemented a high temperature disconnection policy when temperatures are expected to reach 35 degrees Celsius. • In response to increasing wildfire and flooding events, BC Hydro implemented tariff changes in 2021/22 to allow electricity charges to be waived for residential and small business customers under an Evacuation Order that has been in place for at least five days. BC Hydro also waives the customer's last bill, as well as the charge to establish a new electric service when they rebuild, if not covered by their insurance. • BC Hydro has also established processes with the Ministry of Social Development & Poverty Reduction to avoid security deposits and postpone disconnections for customers awaiting decisions on applications for support. BC Hydro also implemented

	tariff changes to allow another customer to act as a guarantor for a residential customer account as an alternative to providing a security deposit. • BC Hydro implemented changes that will delay disconnections where customers demonstrate a medical reason for requiring power. • Minimum Reconnection and Returned Payment Charges have been reduced.
Maintain or improve customer satisfaction by providing timely and responsive service.	**Ongoing** • Our 2022/23 CSAT result of 89 per cent exceeds the target of 85 percent reflecting our ongoing efforts in ensuring customer reliability and continued commitment to customer service and improving customer communications. The residential and commercial customer index 2022/23 scores were relatively consistent with past years' results.
Safely complete the Site C project within the lowest cost and approved schedule, and implement the recommendations of the Milburn Report, reports from independent dam safety experts, other directions from the Minister responsible, and provide quarterly progress and other reporting to Treasury Board and the BC Utilities Commission.	**Complete** • Implemented all 17 recommendations resulting from Peter Milburn's independent review of the Site C project to improve project oversight and governance, as of September 30, 2021. **Ongoing** • As of March 2023, the project was approximately 75 per cent complete and remained on track to have all six generating units fully in-service by late 2025. • In 2022/23, BC Hydro continued to manage the Site C project within the approved $16 billion budget. • There were 12 Site C Project Assurance Board meetings, two workshops and one site tour held in 2022/23. • BC Hydro continues to work collaboratively with the Project Assurance Board, special advisor Peter Milburn, Ernst and Young Canada, the Technical Advisory Board, and independent international dam experts to actively manage ongoing project risks.
Continue to implement government direction resulting from the Comprehensive Review of BC Hydro. Priority initiatives for 2021/22 should include: • Supporting the implementation of the BC Hydrogen Strategy;	**Ongoing** **Hydrogen** • BC Hydro is currently reviewing funding applications for four hydrogen projects, totalling approximately 33 megawatt of new demand.

• Expanding BC Hydro's network of electric vehicle DC fast-charging stations; • Supporting clean technology innovation through Powertech; • Increasing industrial electrification by making it easier and faster for customers to connect to the electricity grid; and • Re-investing new low carbon fuel standard credit revenues in transportation electrification infrastructure, incentives and programs	**EVs** • In 2022/23, BC Hydro installed 33 electric vehicle fast-charging stations at 26 sites. Since 2012/13, we have grown our public charging network, in collaboration with the Province, to 141 fast chargers at 83 sites across B.C. • BC Hydro's EV Infrastructure Five-Year Plan will result in 145 sites and 325 chargers by 2025. The plan comprises mainly 100+kilowatt chargers to meet the increasingly faster charging capabilities of EVs. The total budget is $44.7 million with an anticipated 40 per cent to come from government grants (Natural Resources Canada and Ministry of Energy, Mines and Low Carbon Innovation. **Connections** • BC Hydro is actively working to improve our customer connections process, including improving the end-to-end customer experience, updating distribution extension policy, and building out infrastructure. Key achievements in 2022/23 include: o Changes to improve customer communication, reduce timelines, improve the end-to-end connection process, and staffing additions to accelerate new distribution customer connections. o Engagement with customers to update BC Hydro's Distribution Extension Policy. o Implementation of measures to address localized capacity constraints, including updating feeder loading planning criteria in high growth areas, implementing feeder level Demand Side Management, and advancing voltage conversion work to 25 kilovolt in 12 kilovolt areas.
Develop a short-term electrification plan that builds on the key results of the Comprehensive Review of BC Hydro and supports CleanBC.	**Complete** • In 2021, BC Hydro launched its Electrification Plan, A clean future powered by water, to make it easier and more affordable for people to efficiently use more of B.C.'s clean electricity instead of fossil fuels to power their homes, businesses and vehicles. These actions are expected to result in an additional 3,100 gigawatt hours of load and reducing GHG emissions by 930,000 tonnes per year by the end of Fiscal 2026.
Working with customers, develop efficient and flexible rate proposals for BC Utilities Commission	**Ongoing**

review that will incent greenhouse gas emission reductions and keep rates affordable.	• On February 27, 2023, BC Hydro submitted a residential rate design application to the BC Utilities Commission to request approval of an optional time-of-use rate for the entire residential home, including electric vehicle charging. On March 16, 2023, BC Hydro submitted its Transmission Service Rate Design Application to transition the current stepped rate structure for industrial customers to a flat rate, helping to remove a barrier to electrification.
Actively market 100% clean energy through Powerex to realize new trading opportunities and income for the benefit of BC Hydro ratepayers.	**Ongoing** • In January 2021, Powerex adopted a Clean Energy Trade Standard in light of the growing importance of delivering clean power to its customers. The Standard ensures that exports of clean energy from the BC Hydro system cannot be backfilled with emitting resources, whether within the province or imported, to serve BC Hydro load
Partner with the Province and the federal government to implement the CleanBC Remote Community Energy Strategy to help remote communities, with a focus on Indigenous communities, reduce diesel use and replace it with clean energy.	**Ongoing** • Continued to work with Indigenous communities to advance the development of clean energy generation projects such as solar, stored hydro, run-of-river hydro and biomass projects to reduce or eliminate the use of diesel generation as part of CleanBC. • Supported the Indigenous Clean Energy Opportunities Review to identify and support new clean energy opportunities for Indigenous peoples related to CleanBC, Phase 2 of the Comprehensive Review of BC Hydro and the BC Utilities Commission Inquiry on Indigenous Utilities. • As part of the CleanBC Plan, developed a Non-Integrated Areas Strategy with a focus on diesel reduction and engaged with Indigenous communities. • Nine Indigenous-owned clean energy projects are under development and BC Hydro is advancing these projects with Nations under a technical working group model. It is expected that these projects will reduce diesel consumption by about 4 million litres per year, or 20 per cent of the diesel that BC Hydro uses to generate electricity in the Non-Integrated Areas.
Work with the Province to secure additional federal funding and bring into service transmission projects that will reduce or avoid greenhouse gas emissions and help meet its climate goals.	**Ongoing** • Together with Natural Resources Canada and a number of other partners, BC Hydro will be piloting EV charging technologies which aims to reduce the cost

	of implementing EV charging infrastructure in multi-use residential buildings, commercial and public settings. In addition, this pilot will assess demand response functionality, which can reduce the impacts of EV charging on BC Hydro's system.

Appendix B: Subsidiaries and Operating Segments

Active Subsidiaries

Powerex Corp.

Powerex Corp., an energy marketer, is a wholly owned corporate subsidiary of BC Hydro and a key participant in wholesale energy markets across North America. Powerex's business consists of trading wholesale power and natural gas, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), ancillary energy services and financial energy products.

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 net income. Over the previous five years, Powerex's net income has ranged from $192 million to $1,052 million (2018/19 to 2022/23). For more information, visit powerex.com.

Board of Directors

- Catherine Roome - Chair
- Sam Drier
- Amanda Hobson
- Marilyn Mauritz
- Chris O'Riley

Powertech Labs Inc.

Powertech Labs Inc., operating in Surrey since its inception in 1979, is a wholly owned subsidiary of BC Hydro. Powertech provides innovative solutions, specialized testing and technical expertise to industry partners globally to create a safe and sustainable energy future. Powertech is internationally recognized for its technical leadership in a range of fields related to electric utilities and sustainable energy industries. It is also a leader in hydrogen technology, having long-standing experience designing and producing innovative hydrogen vehicle refueling systems, and is central to BC Hydro's commitment to support the Province's B.C. Hydrogen Strategy.

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

Over the last five years, Powertech's revenue has ranged from $43 million to $54 million (2018/19 to 2022/23) with a net income (loss) in the range of $-1 million to $5.4 million. For more information, visit powertechlabs.com.

Board of Directors

- Chris O'Riley - Chair
- Melissa Holland
- Vasee Navaratnam
- John Nunn
- David Wong

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, 2023, 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

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 8, 2023. The consolidated financial statements have also been reviewed by the Audit, Finance & Capital 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 and appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit, Finance & Capital Committee.

The consolidated financial statements have been examined by independent external auditors. 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 International Financial Reporting Standards. The Independent Auditors' Report, which follows, outlines the scope of their examination and their opinion.

The Board of Directors, through the Audit, Finance & Capital Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit, Finance & Capital 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 to review the financial statements before recommending approval by the Board of Directors. The internal and external auditors have full and open access to the Audit, Finance & Capital Committee, with and without the presence of management.

Chris O'Riley

Chris O'Riley
President and Chief Executive Officer

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

Vancouver, Canada

June 8, 2023

Office of the
Auditor General
of British Columbia

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Independent Auditor's Report

To the Board of Directors of the British Columbia Hydro and Power Authority, and
To the Minister of Energy, Mines and Low Carbon Innovation, Province of British Columbia

Opinion

I have audited the accompanying consolidated financial statements of the British Columbia Hydro and Power Authority ("the group"), which comprise the consolidated statement of financial position at March 31, 2023, and the consolidated statements of comprehensive income, changes in equity and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

In my opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the group as at March 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Consolidated Financial Statements section of my report. I am independent of the group in accordance with the ethical requirements that are relevant to my audit of the consolidated financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other Accompanying Information

Management is responsible for the other information. The other information comprises the information included in the Annual Service Plan Report, but does not include the consolidated financial statements and my auditor's report thereon. The Annual Service Plan Report is expected to be made available to me after the date of this auditor's report.

My opinion on the consolidated financial statements does not cover the other information accompanying the financial statements and I do not express any form of assurance conclusion thereon.

In connection with my audit of the consolidated financial statements, my responsibility is to read the other information that I have obtained prior to the date of my auditor's report and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or my knowledge obtained during the audit or otherwise appears to be materially misstated.

When I read the Annual Service Plan Report, if I conclude that there is a material misstatement therein, I am required to communicate the matter to those charged with governance.

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

Those charged with governance are responsible for the oversight of the financial reporting process. Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of the consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting when the group will continue its operations for the foreseeable future.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

My objectives are to obtain reasonable assurance about whether the group's consolidated 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 my 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 aggregate, they could reasonably be expected to influence the economic decision of users taken on the basis of these consolidated financial statements.

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

- Identify and assess the risks of material misstatement of the consolidated 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 my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than 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 group'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 group's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the group to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the group to express an opinion on the consolidated financial statements. I am responsible for the direction, supervision and performance of the group audit and I remain solely responsible for my audit opinion.

I 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 I identify during my audit.

I also provide those charged with governance with a statement that I have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on my independence, and where applicable, related safeguards.

Michael A. Pickup, FCPA, FCA
Auditor General of British Columbia

Victoria, British Columbia, Canada
June 8, 2023

Audited Financial Statements

Consolidated Statements of Comprehensive Income

for the years ended March 31 (in millions)	**2023**	2022
Revenues (Note 4)		
Domestic	**$ 5,304**	$ 5,619
Trade	**2,723**	1,972
	8,027	7,591
Expenses		
Operating expenses (Note 5)	**6,009**	5,794
Finance charges (Note 6)	**496**	521
Net Income Before Movement in Regulatory Balances	**1,522**	1,276
Net movement in regulatory balances (Note 15)	**(1,162)**	(608)
Net Income	**360**	**668**
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 23)	**18**	(34)
Reclassification to income of derivatives designated as cash flow hedges (Note 23)	**(91)**	39
Foreign currency translation gains (losses)	**54**	(12)
Items That Will Not Be Reclassified to Net Income		
Actuarial gain	**251**	776
Other Comprehensive Income before movement in regulatory balances	**232**	**769**
Net movements in regulatory balances (Note 15)	**(282)**	(758)
Other Comprehensive Income (Loss)	**(50)**	11
Total Comprehensive Income	**$ 310**	$ 679

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Financial Position

(in millions)		As at March 31, 2023		As at March 31, 2022
ASSETS				
Current Assets				
Cash and cash equivalents (Note 8)	**$**	**148**	$	99
Accounts receivable and accrued revenue (Note 9)		**894**		802
Inventories (Note 10)		**387**		264
Prepaid expenses		**186**		156
Current portion of derivative financial instrument assets (Note 23)		**494**		315
		2,109		1,636
Non-Current Assets				
Property, plant and equipment (Note 11)		**36,926**		34,038
Right-of-use assets (Note 12)		**1,305**		1,248
Intangible assets (Note 13)		**639**		640
Derivative financial instrument assets (Note 23)		**319**		242
Other non-current assets (Note 14)		**542**		540
		39,731		36,708
Total Assets		**41,840**		38,344
Regulatory Balances (Note 15)		**3,946**		4,390
Total Assets and Regulatory Balances	**$**	**45,786**	$	42,734
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities (Note 16)	**$**	**1,953**	$	1,760
Current portion of long-term debt (Note 17)		**2,958**		3,292
Current portion of unearned revenues and contributions in aid (Note 20)		**108**		100
Current portion of derivative financial instrument liabilities (Note 23)		**474**		228
		5,493		5,380
Non-Current Liabilities				
Long-term debt (Note 17)		**24,057**		22,659
Lease liabilities (Note 19)		**1,376**		1,327
Derivative financial instrument liabilities (Note 23)		**325**		177
Unearned revenues and contributions in aid (Note 20)		**2,615**		2,418
Post-employment benefits (Note 22)		**731**		893
Other non-current liabilities (Note 24)		**1,354**		1,355
		30,458		28,829
Total Liabilities		**35,951**		34,209
Regulatory Balances (Note 15)		**2,479**		1,479
Total Liabilities and Regulatory Balances		**38,430**		35,688
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**7,354**		6,994
Accumulated other comprehensive loss		**(58)**		(8)
		7,356		7,046
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$**	**45,786**	$	42,734

Commitments and Contingencies (Notes 11 and 25)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

Lori Wanamaker
Board Chair

Victoria McMillan, CPA, CA
Chair, Audit, Finance & Capital Committee

Consolidated Statements of Changes in Equity

(in millions)	Cumulative Translation Reserve	Unrealized Income (Loss) on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2021	$ (19)	$ -	$ (19)	$ 60	$ 6,326	$ 6,367
Comprehensive Income	6	5	11	-	668	679
Balance as at March 31, 2022	(13)	5	(8)	60	6,994	7,046
Comprehensive Income (Loss)	23	(73)	(50)	-	360	310
Balance as at March 31, 2023	$ 10	$ (68)	$ (58)	$ 60	$ 7,354	$ 7,356

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

for the years ended March 31 (in millions)	**2023**	2022
Operating Activities		
Net income	**$ 360**	$ 668
Regulatory account transfers (Note 15)	**1,162**	608
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 7)	**1,052**	1,079
Unrealized gains on derivative financial instruments	**(55)**	(235)
Post-employment benefits expense	**98**	146
Interest accrual	**874**	786
Other items	**47**	74
	3,538	3,126
Changes in working capital and other assets and liabilities (Note 18)	**(100)**	166
Interest paid	**(919)**	(877)
Cash provided by operating activities	**2,519**	2,415
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(3,532)**	(3,127)
Cash used in investing activities	**(3,532)**	(3,127)
Financing Activities		
Long-term debt issued (Note 17)	**1,498**	1,568
Long-term debt retired (Note 17)	**(500)**	(526)
Receipt of revolving borrowings	**7,438**	8,733
Repayment of revolving borrowings	**(7,494)**	(8,744)
Payment of principal portion of lease liability	**(71)**	(82)
Settlement of hedging derivatives	**205**	(151)
Other items	**(14)**	(24)
Cash provided by financing activities	**1,062**	774
Increase in cash and cash equivalents	**49**	62
Cash and cash equivalents, beginning of year	**99**	37
Cash and cash equivalents, end of year	**$ 148**	$ 99

See Note 18 for Cash flow supplement - changes in liabilities arising from financing activities

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 Province 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 International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). The significant accounting policies are set out in Note 3.

Certain amounts in the prior year's comparative figures have been reclassified to conform to the current year's presentation.

These consolidated financial statements were approved by the Board of Directors on June 8, 2023.

(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 increases 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 22 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.

The Company is currently defending certain lawsuits where management must make judgments, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management has obtained the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

(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) Useful Life of Property, Plant and Equipment and Intangible Assets
Estimation and judgement 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.

(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 decision of 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.

(vii) Revenues
For contributions in aid of construction revenue, management must make judgments when determining the period over which revenue is recognized when the associated contracts do not specify a finite period over which service is provided.

For revenue contracts where a significant financing component is present, management must make judgments when determining the appropriate discount rate to use.

Note 3: Significant 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 decisions 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 decisions and approvals by 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 are assessed to no longer be probable based on management's judgment or the refund of these liability balances are 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 statement 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 decisions.

(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.

Domestic revenues comprise sales to customers within the province of British Columbia, and sales of energy outside the province that are under long-term contracts. Sales that are surplus to domestic load requirements and other sales outside the province are classified as trade.

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 comprise 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 and 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. Impairment of cash and cash equivalent and restricted cash is evaluated by reference to the credit quality of the underlying financial institution.

(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.

Impairment losses recognized in prior periods are assessed at the reporting date for any indications that the loss has decreased or no longer exists. Impairment reversals are recognized immediately in net income when the recoverable amount of an asset increases above the impaired net book value, not to exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

(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 trade 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 is 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 not in a hedging relationship	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
Revolving 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 23.

(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 prorated 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. 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 reasonably measured. Management obtains the advice of its external 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 25.

(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.

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 activity in the United States.

(t) New Standards and Amendments Not Yet Adopted

A number of amendments to standards and interpretations, are not yet effective for the year ended March 31, 2023, 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:

- Three Amendments to IAS 1, *Presentation of Financial Statements* (effective April 1, 2023 and April 1, 2024)
- Amendments to IAS 8, *Accounting Policies, Changes in Accounting Estimates and Errors* (effective April 1, 2023)
- Amendments to IFRS 16, *Leases* (effective April 1, 2024)
- IFRS 17, *Insurance Contracts* (effective April 1, 2023)

The Company does not expect the adoption of the new or amended standards to have a material impact on the consolidated financial statements.

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)		**2023**		2022
Domestic				
Residential	**$**	**2,146**	$	2,342
Light industrial and commercial		**1,840**		1,952
Large industrial		**848**		854
Other sales		**470**		471
Total Domestic		**5,304**		5,619
Total Trade[1]		**2,723**		1,972
Total Revenue	**$**	**8,027**	$	7,591

[1] Includes revenue recognized under IFRS 9, *Financial Instruments* (2023 - $942M ; 2022 - $811M).

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, 2023 was $834 million (2022 - $757 million).

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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, 2023**		March 31, 2022
Unearned revenues (Note 20)	**$**	**325**	$	322
Contributions in aid (Note 20)		**2,398**		2,196
Customer deposits		**67**		22
	$	**2,790**	$	2,540

The following table reconciles the changes in the contract liabilities balances during the years ended March 31, 2023 and 2022:

(in millions)		**Contract Liabilities**
Balance at April 1, 2021	**$**	**2,363**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(130)
Increases due to cash received, excluding amounts recognized as revenue during the period		278
Other[1]		29
Balance at March 31, 2022		**2,540**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(136)
Increases due to cash received, excluding amounts recognized as revenue during the period		372
Other[1]		14
Balance at March 31, 2023	**$**	**2,790**

[1] Other includes finance charges and foreign exchange adjustments

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, 2023.

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(in millions)	Less than 1 year	Between 1 and 5 years	More than 5 years	Total
Energy sales	$ 130	$ 156	$ 6	$ 292
Contributions in aid	64	261	2,073	2,398
Skagit River Agreement	30	119	1,128	1,277
Other	52	105	37	194
	$ 276	$ 641	$ 3,244	$ 4,161

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)	**2023**	2022
Electricity and gas purchases	**$ 2,442**	$ 2,388
Water rentals	**358**	346
Transmission charges	**323**	268
Personnel expenses	**762**	736
Materials and external services	**757**	672
Amortization and depreciation (Note 7)	**1,052**	1,079
Grants and taxes	**296**	286
Other costs, net of recoveries	**105**	97
Capitalized costs	**(86)**	(78)
	$ 6,009	$ 5,794

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2023 AND 2022

Note 6: Finance Charges

(in millions)		**2023**		2022
Interest on long-term debt	**$**	**874**	$	786
Interest on lease liabilities		**46**		45
Interest on defined benefit plan obligations (Note 22)		**43**		56
Mark-to-market gains on derivative financial instruments (Note 23)		**(201)**		(150)
Other		**83**		43
Capitalized interest		**(349)**		(259)
	$	**496**	$	521

The capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 3.3 per cent (2022 - 3.1 per cent).

Note 7: Amortization and Depreciation

(in millions)		**2023**		2022
Depreciation of property, plant and equipment (Note 11)	**$**	**888**	$	893
Depreciation of right-of-use assets (Note 12)		**82**		96
Amortization of intangible assets (Note 13)		**82**		90
	$	**1,052**	$	1,079

Note 8: Cash and Cash Equivalents

(in millions)		**March 31, 2023**		March 31, 2022
Cash	**$**	**78**	$	27
Short-term investments		**70**		72
	$	**148**	$	99

Note 9: Accounts Receivable and Accrued Revenue

(in millions)		**March 31, 2023**		March 31, 2022
Accounts receivable	**$**	**521**	$	451
Accrued revenue		**251**		261
Other		**122**		90
	$	**894**	$	802

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

Note 10: Inventories

(in millions)		**March 31, 2023**		March 31, 2022
Materials and supplies and Environmental Products	**$**	**208**	$	188
Natural Gas and Certain Carbon products		**179**		76
	$	**387**	$	264

There were no materials, supplies, and environmental products inventory impairments during the years ended March 31, 2023 and 2022. Natural gas and certain carbon products inventory held for trading are measured at fair value less costs to sell and therefore, not subject to impairment testing.

Inventories recognized as an expense during the year amounted to $139 million (2022 - $116 million).

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FOR THE YEARS ENDED MARCH 31, 2023 AND 2022

Note 11: Property, Plant, and Equipment

(in millions)	Generation	Transmission	Distribution	Land & Buildings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at April 1, 2021	$ 9,784	$ 8,108	$ 6,941	$ 850	$ 979	$ 8,098	$ 34,760
Net additions	293	434	517	33	68	2,034	3,379
Disposals and retirements	(25)	(13)	(40)	(1)	(35)	-	(114)
Impairments	-	-	-	-	(12)	(57)	(69)
Balance at March 31, 2022	10,052	8,529	7,418	882	1,000	10,075	37,956
Net additions	292	303	585	37	88	2,534	3,839
Disposals and retirements	(12)	(27)	(44)	(6)	(47)	(4)	(140)
Balance at March 31, 2023	$ 10,332	$ 8,805	$ 7,959	$ 913	$ 1,041	$ 12,605	$ 41,655
Accumulated Depreciation							
Balance at April 1, 2021	$ (955)	$ (902)	$ (803)	$ (111)	$ (312)	$ -	$ (3,083)
Depreciation expense	(268)	(257)	(231)	(27)	(110)	-	(893)
Disposals and retirements	11	6	10	-	29	-	56
Impairments	-	-	-	-	2	-	2
Balance at March 31, 2022	(1,212)	(1,153)	(1,024)	(138)	(391)	-	(3,918)
Depreciation expense	(272)	(247)	(245)	(28)	(96)	-	(888)
Disposals and retirements	7	17	15	-	38	-	77
Balance at March 31, 2023	$ (1,477)	$ (1,383)	$ (1,254)	$ (166)	$ (449)	$ -	$ (4,729)
Net carrying amounts							
At March 31, 2022	$ 8,840	$ 7,376	$ 6,394	$ 744	$ 609	$ 10,075	$ 34,038
At March 31, 2023	$ 8,855	$ 7,422	$ 6,705	$ 747	$ 592	$ 12,605	$ 36,926

(i) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1.24 billion (2022 - $1.21 billion) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2023 was $34 million (2022 - $33 million).

(ii) 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 government grants of $4 million during the year ended March 31, 2023 (2022 - $7 million).

(iii)The Company has contractual commitments to spend $1.79 billion on major property, plant and equipment projects (on individual projects greater than $20 million) as at March 31, 2023.

(iv)The Company recognized impairments, mainly to unfinished construction assets, as a result of events that have caused the construction of the asset to no longer be viable.

Note 12: Right-of-Use Assets

(in millions)	Long-term energy purchase agreements	Property	Equipment/ Other	Total
Cost				
Balance at April 1, 2021	$ 1,984	$ 58	$ 7	$ 2,049
Net additions	29	-	-	29
Disposals and retirements	-	-	(3)	(3)
Balance at March 31, 2022	2,013	58	4	2,075
Net additions	123	17	-	140
Disposals and retirements	-	(1)	-	(1)
Balance at March 31, 2023	$ 2,136	$ 74	$ 4	$ 2,214
Accumulated Depreciation				
Balance at April 1, 2021	$ (703)	$ (25)	$ (4)	$ (732)
Depreciation expense	(91)	(5)	-	(96)
Disposals and retirements	-	1	-	1
Balance at March 31, 2022	(794)	(29)	(4)	(827)
Depreciation expense	(78)	(4)	-	(82)
Disposals and retirements	-	-	-	-
Balance at March 31, 2023	$ (872)	$ (33)	$ (4)	$ (909)
Net carrying amounts				
At March 31, 2022	$ 1,219	$ 29	$ -	$ 1,248
At March 31, 2023	$ 1,264	$ 41	$ -	$ 1,305

Refer to Note 19 for additional information on right-of-use assets and lease liabilities.

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Note 13: Intangible Assets

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Work in Progress	Total
Cost					
Balance at April 1, 2021	$ 320	$ 145	$ 475	$ 37	$ 977
Net additions	9	8	60	15	92
Disposals and retirements	-	-	-	-	-
Balance at March 31, 2022	329	153	535	52	1,069
Net additions	8	10	44	21	83
Disposals and retirements	-	-	(6)	-	(6)
Balance at March 31, 2023	$ 337	$ 163	$ 573	$ 73	$ 1,146
Accumulated Amortization					
Balance at April 1, 2021	$ (3)	$ (84)	$ (253)	$ -	$ (340)
Amortization expense	(1)	(19)	(70)	-	(90)
Disposals and retirements	-	-	1	-	1
Balance at March 31, 2022	(4)	(103)	(322)	-	(429)
Amortization expense	(1)	(16)	(65)	-	(82)
Disposals and retirements	-	-	4	-	4
Balance at March 31, 2023	$ (5)	$ (119)	$ (383)	$ -	$ (507)
Net carrying amounts					
At March 31, 2022	$ 325	$ 50	$ 213	$ 52	$ 640
At March 31, 2023	$ 332	$ 44	$ 190	$ 73	$ 639

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.

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Note 14: Other Non-Current Assets

(in millions)		**March 31, 2023**		March 31, 2022
Non-current receivables	**$**	**134**	$	134
Sinking funds		**237**		210
Non-current Site C prepaid expenses		**159**		184
Other		**12**		12
	$	**542**	$	540

Non-Current Receivables

Included in the non-current receivables balance are $116 million of receivables (2022 - $119 million) attributable to other contributions receivable 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.

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, 2023**			March 31, 2022		
		Carrying Value	**Weighted Average Effective Rate[1]**		Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$**	**141**	**4.1 %**	$	127	2.9 %
Other provincial government and crown corporation bonds		**93**	**4.4 %**		80	2.9 %
Other		**3**	**-**		3	-
	$	**237**		$	210	

[1]Rate calculated on market yield to maturity.

Effective December 2005, all sinking fund payment requirements on all new and outstanding debt were removed. The existing sinking funds relate to debt that mature in fiscal 2026 and fiscal 2037.

Note 15: 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)	**2023**	2022
Net decrease in regulatory balances related to net income	**$ (1,162)**	$ (608)
Net decrease in regulatory balances related to OCI	**(282)**	(758)
	$ (1,444)	$ (1,366)

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 2022*	*Addition / (Reduction)*	*Interest[A]*	*Amortization*	*Net Change[B]*	***As at March 31 2023***	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ 105	$ (96)	$ 2	$ (11)	$ (105)	**$ -**	Note C
Load Variance	33	(32)	-	(1)	(33)	**-**	Note C
Demand-Side Management	868	101	-	(111)	(10)	**858**	1-15
Debt Management	286	(201)	-	(18)	(219)	**67**	5-34
First Nations Provisions & Costs	469	49	1	(34)	16	**485**	1-9 Note G
Site C	542	6	18	-	24	**566**	Note E
CIA Amortization	68	(5)	-	-	(5)	**63**	17
Environmental Provisions & Costs	234	15	(1)	(32)	(18)	**216**	Note F, G
Smart Metering & Infrastructure	151	-	5	(26)	(21)	**130**	6
IFRS Pension	382	-	-	(38)	(38)	**344**	9
IFRS Property, Plant & Equipment	1,039	-	-	(32)	(32)	**1,007**	29-38
Other Regulatory Accounts	213	39	4	(46)	(3)	**210**	1-20, Note F, H
Total Regulatory Assets	4,390	(124)	29	(349)	(444)	**3,946**	
Regulatory Liabilities							
Heritage Deferral	-	25	-	7	32	**32**	Note C
Non-Heritage Deferral	185	(51)	8	(32)	(75)	**110**	Note C
Trade Income Deferral	504	747	26	(87)	686	**1,190**	Note D
Biomass Energy Program	40	40	2	(7)	35	**75**	Note C
Inflationary Pressures	-	57	1	-	58	**58**	Note I
Load Variance	-	28	-	5	33	**33**	Note C
Non-Current Pension Costs	669	155	-	30	185	**854**	4-13
Other Regulatory Accounts	81	62	3	(19)	46	**127**	Note C, F
Total Regulatory Liabilities	1,479	1,063	40	(103)	1,000	**2,479**	
Net Regulatory Asset	$ 2,911	$ (1,187)	$ (11)	$ (246)	$ (1,444)	**$ 1,467**	

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(in millions)	*As at April 1 2021*	*Addition / (Reduction)*	*Interest[A]*	*Amortization*	*Net Change[B]*	*As at March 31 2022*	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ 65	$ 38	$ 2	$ -	$ 40	$ 105	Note C
Load Variance	110	(79)	2	-	(77)	33	Note C
Demand-Side Management	881	94	-	(107)	(13)	868	1-15
Debt Management	449	(153)	-	(10)	(163)	286	6-34
First Nations Provisions & Costs	486	15	2	(34)	(17)	469	2-9 Note G
Total Finance Charges	-	8	-	31	39	39	Note F
Non-Current Pension Costs	114	(66)	-	(48)	(114)	-	5-13
Site C	523	3	16	-	19	542	Note E
CIA Amortization	73	(5)	-	-	(5)	68	18
Environmental Provisions & Costs	294	(1)	(1)	(58)	(60)	234	Note F, G
Smart Metering & Infrastructure	173	-	5	(27)	(22)	151	7
IFRS Pension	421	-	-	(39)	(39)	382	10
IFRS Property, Plant & Equipment	1,070	-	-	(31)	(31)	1,039	30-39
Other Regulatory Accounts	116	62	4	(8)	58	174	3-7, Note H
Total Regulatory Assets	4,775	(84)	30	(331)	(385)	4,390	
Regulatory Liabilities							
Non-Heritage Deferral	153	28	4	-	32	185	Note C
Trade Income Deferral	227	264	13	-	277	504	Note D
Biomass	14	25	1	-	26	40	Note C
Non-Current Pension Costs	-	602	-	67	669	669	5-13
Other Regulatory Accounts	104	45	-	(68)	(23)	81	3-6, Note C, F
Total Regulatory Liabilities	498	964	18	(1)	981	1,479	
Net Regulatory Asset	$ 4,277	$ (1,048)	$ 12	$ (330)	$ (1,366)	$ 2,911	

[A] As permitted, interest charges were accrued to certain regulatory balances at a rate of 3.3 per cent for the year ended March 31, 2023 (2022 – 3.1 per cent).

[B] Net Change includes a net decrease to net income of $1.16 billion (2022 – $608 million) and a net decrease to other comprehensive income of $282 million (2022 – $758 million).

[C] The balances in these regulatory accounts are recovered in rates through the Deferral Account Rate Rider (DARR), which is an additional charge on customer bills and generally has a recovery period of 4 to 6 years. In its preliminary decision (Decision) on the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the BCUC approved the requested DARR refund of 2.0 per cent (2022 – 0 percent) for fiscal 2023 on an interim basis effective April 1, 2022 and 1.0 per cent for fiscal 2024 on interim basis. Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover all these balances.

[D] The Trade Income Deferral Account balance will be recovered through the DARR in fiscal 2023 and fiscal 2024 as described in footnote C above. Commencing in fiscal 2025, the balance will be recovered over a three year period, through the Trade Income Rate Rider (TIRR), which is a separate additional charge or refund on customer bills. The BCUC directed BC Hydro to file for approval of the TIRR annually in a filing separate from the Revenue Requirements Application.

[E] In its Decision on the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the BCUC approved the recovery of the balance in this account over the forecasted weighted average expected useful life of the Site C assets, currently estimated at 84 years, commencing in fiscal 2025.

[F] 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.

[G] 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 actual expenditures are incurred and transferred to the respective regulatory cost account.

[H] The balance includes an account that is expected to self-clear based on forecast net gains from real property sales experienced over fiscal 2020 to fiscal 2024, resulting in a forecast zero balance by the end of fiscal 2024, subject to potential interest charges.

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

Rate Regulation

On November 18, 2022, BC Hydro submitted an application to the BCUC request for a new Cloud Costs regulatory account. On April 18, 2023, the BCUC approved BC Hydro's request for the Cloud Costs regulatory account to capture cloud arrangement implementation costs and directed BC Hydro to establish a separate Cloud Usage Fee regulatory account to capture annual usage fee variances for unplanned cloud arrangements. The BCUC also approved recovery of the Cloud Costs regulatory account over the expected term of the cloud arrangement, the Cloud Usage Fees over the following test period and the application of interest to the accounts. The Cloud Costs regulatory account and Cloud Usage Fees regulatory account were included within Other Regulatory Accounts – assets in the table above.

On November 18, 2022, the Government of B.C. issued a Direction to the BCUC respecting Residential and Commercial Customer Account Credits (B.C. Reg 163/2021, Order in Council No. 571) under section 3 of the Utilities Commission Act. On November 28, 2022, the BCUC issued Order No. G-341-22 as directed to enable the provision of residential and commercial customer account credits and several changes to BC Hydro's regulatory accounts. The Order authorized BC Hydro to establish a Customer Credit Regulatory Account and Inflationary Pressures Regulatory Account and transfer $320 million and $74 million, respectively, from the Trade Income Deferral Account to these new accounts. In addition, it authorized BC Hydro to transfer $6 million from the Trade Income Deferral Account to the Customer Crisis Fund Regulatory Account. It also required BC Hydro to provide account credits to commercial and residential customers, defer the amount of the customer credits issued to the Customer Credit Regulatory Account and allows BC Hydro to defer specified inflationary pressure amounts to the Inflationary Pressures Regulatory Account. The Customer Crisis Fund Regulatory Account and Customer Credit Regulatory Account were included within the Other Regulatory Accounts - liabilities in the table above.

On March 31, 2023, BC Hydro submitted an application to the BCUC seeking approval to reinstate a $320 million regulatory liability to the Trade Income Deferral Account. The effect of the reinstatement of the $320 million regulatory liability is that the customer credits issued in accordance with the Direction and BCUC Order No. G-341-22 will have been funded through BC Hydro's operations (i.e., by a reduction in BC Hydro's actual fiscal 2023 net income) and not by ratepayers. Customers will retain the credits they received and there will be no bill adjustments because of the application. The BCUC review of BC Hydro's application to reinstate the $320 million regulatory liability in the Trade Income Deferral Account is currently underway and the BCUC will issue its decision in due course. The financial impact of the requested reinstatement has been incorporated in these financial statements in accordance with the Company's rate regulation accounting policy, whereby BC Hydro recognizes the impacts of requests in advance of a final decision by the BCUC if management considers it is probable that the BCUC will approve the request. As a result, the Customer Credit Regulatory Account had a $nil account balance at March 31, 2023.

On April 21, 2023, the BCUC issued its preliminary Decision on BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application and issued a series of compliance directives that impacted BC Hydro's fiscal 2023 financial statements. The financial impact of the Decision has been incorporated in these financial statements. The impact was a revised estimated bill decrease for fiscal 2023 of 1.32 per cent. This is a 0.06 per cent change in the bill impact compared to the 1.38 per cent interim bill decrease approved by the BCUC for fiscal 2023. In addition, the BCUC directed BC Hydro to establish two new regulatory accounts - the Electrification Customer Connection Costs regulatory account and the Site C Variance Costs regulatory account. The Electrification Customer Connection Costs regulatory account is included within Other Regulatory Accounts in the table above and the Site C Variance Costs account had a $nil account balance as at March 31, 2023.

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 credit on customer bills. In its recent Decision, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2023 and fiscal 2024. 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 Trade Income Deferral account, the Load Variance account, the Biomass Energy Program Variance account and the Low Carbon Fuel Credits Variance Regulatory Account). Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances other than the Trade Income Deferral Account.

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. In its recent Decision, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2023 and fiscal 2024. Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the

DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances other than the Trade Income Deferral Account.

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. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills. In its recent Decision, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2023 and fiscal 2024. Commencing in fiscal 2025, the Trade Income Deferral Account will be recovered in rates, over a three year period, through the Trade Income Rate Rider (TIRR), which is a separate additional charge or credit on customer bills. The BCUC directed BC Hydro to file for approval of the TIRR annually in a filing separate from the RRA.

Load Variance

This account is intended to capture the variance between planned and actual domestic customer load (i.e., customer demand). The account is 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 NHDA. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills. In its recent Decision, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2023 and fiscal 2024. Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances other than the Trade Income Deferral Account.

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 also 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 NHDA. Prior to the creation of this account, these variances would have been in the scope of the Non-Heritage Deferral Account. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills. In its recent Decision, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2023 and fiscal 2024. Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances other than the Trade Income Deferral Account.

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 new account. BC Hydro has not requested recovery of the Inflationary Pressures Regulatory Account as of March 31, 2023, but expects the balance to be fully drawn down to zero over time as costs are deferred to the regulatory account.

Demand-Side Management

Demand-Side Management expenditures are deferred and amortized on a straight-line basis over the anticipated 15 year period of benefit of the expenditures. 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.

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).

Site C

Site C Project expenditures incurred in fiscal 2007 through the third quarter of fiscal 2015 were deferred. In December 2014, the Province approved a final investment decision for the Site C

Project, resulting in expenditures being capitalized in property, plant and equipment starting in the fourth quarter of fiscal 2015. In its recent Decision, the BCUC approved BC Hydro's request to begin amortizing the balance of the Site C Regulatory Account once the Site C assets are in service in fiscal 2025 over the weighted average expected useful life of the Site C assets, currently estimated at 84 years.

Contributions in Aid (CIA) of Construction Amortization

This account captures the difference in revenue requirement impacts of the 45 year amortization period the Company uses as per a depreciation study and the 25 year amortization period determined by the BCUC.

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*, the Asbestos requirements of the Occupational Health and Safety Regulations under the jurisdiction of WorkSafe BC and the remediation of environmental contamination at a property occupied by a predecessor company.
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, 2019) 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, 2019). 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 mark-to-market 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.

Other Regulatory Accounts

Other regulatory asset and liability accounts with individual balances less than $50 million include the following: Foreign Exchange Gains and Losses, Total Finance Charges, Amortization of Capital Additions, Real Property Sales, Customer Crisis Fund, Electric Vehicle Fast Charging, Depreciation Study, Project Write-off, Mining Customer Payment Plan, Cloud Costs, Cloud Usage Fees, Mandatory Reliability Standards Costs, Load Attraction Costs, Storm Restoration Costs, Dismantling Cost, Post-Employment Benefit Current Pension Costs, Low Carbon Fuel Credits, Customer Credits, Electrification Customer Connection Costs, and Site C Variance Costs.

Note 16: Accounts Payable and Accrued Liabilities

(in millions)		**March 31, 2023**		March 31, 2022
Accounts payable	**$**	**613**	$	420
Accrued liabilities		**1,087**		1,125
Current portion of lease liabilities (Note 19)		**72**		52
Current portion of other long-term liabilities (Note 24)		**130**		112
Other		**51**		51
	$	**1,953**	$	1,760

Note 17: Long-Term Debt and Debt Management

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

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The Company has a commercial paper borrowing program with the Province which is limited to $5.50 billion (2022 - $5.50 billion) and is included in revolving borrowings. At March 31, 2023, the outstanding amount under the borrowing program was $2.76 billion (2022 - $2.79 billion).

For the year ended March 31, 2023, the Company issued bonds for net proceeds of $1.50 billion (2022 - $1.57 billion) and a par value of $1.73 billion (2022 - $1.58 billion), a weighted average effective interest rate of 4.0 per cent (2022 - 2.4 per cent) and a weighted average term to maturity of 18.6 years (2022 - 21.6 years).

For the year ended March 31, 2023, the Company redeemed bonds with a par value of $500 million (2022 - $526 million).

Long-term debt, expressed in Canadian dollars, is summarized in the following table by year of maturity:

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(in millions)	March 31, 2023					March 31, 2022				
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:										
2023	$ -	-	-	$ -	-	$ 500	-	-	$ 500	6.8
2024	200	-	-	200	5.9	200	-	-	200	5.9
2025	10	-	-	10	5.5	10	-	-	10	5.5
2026	900	676	387	1,963	3.6	900	625	365	1,890	3.6
2027	850	-	-	850	2.4	850	-	-	850	2.4
2028	1,000	-	-	1,000	2.8	-	-	-	-	-
1-5 years	2,960	676	387	4,023	3.3	2,460	625	365	3,450	3.9
6-10 years	6,510	-	-	6,510	3.1	6,535	-	-	6,535	2.9
11-15 years	-	405	203	608	5.2	-	375	192	567	5.1
16-20 years	3,273	-	-	3,273	4.3	1,250	-	-	1,250	4.9
21-25 years	2,565	-	-	2,565	3.7	4,588	-	-	4,588	3.9
26-30 years	7,170	-	-	7,170	3.0	5,545	-	-	5,545	2.9
Over 30 years	110	-	-	110	3.4	985	-	-	985	2.7
Bonds	$ 22,588	$ 1,081	$ 590	$ 24,259	3.4	$ 21,363	$ 1,000	$ 557	$ 22,920	3.4
Revolving borrowings	2,115	643	-	2,758	4.5	1,910	882	-	2,792	0.6
	$ 24,703	$ 1,724	$ 590	$ 27,017		$ 23,273	$ 1,882	$ 557	$ 25,712	
Adjustments to carrying value resulting from discontinued hedging activities	7	18	-	25		8	18	-	26	
Unamortized premium, discount, and issue costs	(18)	(7)	(2)	(27)		223	(8)	(2)	213	
	$ 24,692	$ 1,735	$ 588	$ 27,015		$ 23,504	$ 1,892	$ 555	$ 25,951	
Less: Current portion	(2,315)	(643)	-	(2,958)		(2,410)	(882)	-	(3,292)	
Non-current long-term debt	$ 22,377	$ 1,092	$ 588	$ 24,057		$ 21,094	$ 1,010	$ 555	$ 22,659	

[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, 2023 in a net liability position of $8 million (2022 – net liability of $27 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**March 31, 2023**	March 31, 2022
Cross-Currency Swaps		
Euro dollar (€) to Canadian dollar - notional amount[1]	**€ 402**	€ 402
Euro dollar to Canadian dollar - weighted average contract rate	**1.47**	1.47
Weighted remaining term	**5 years**	6 years
Foreign Currency Forwards		
United States dollar (US$) to Canadian dollar - notional amount[1]	**US$ 1,057**	US$ 1,279
United States dollar to Canadian dollar - weighted average contract rate	**1.30**	1.26
Weighted remaining term	**4 years**	4 years

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

The following bond locks and forward swap contracts were in place at March 31, 2023 with a net asset position of $175 million (2022 - net asset of $179 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $2.88 billion (2022 - $3.73 billion) of planned 10 and 30 year debt (2022 - 10 and 30 year debt) to be issued on dates ranging from June 2023 to October 2026 (2022 - June 2022 to October 2025).

(in millions)	**March 31, 2023**	March 31, 2022
Bond Locks		
Canadian dollar - notional amount[1]	**$ -**	$ 575
Weighted forecast borrowing yields	**-**	2.48%
Weighted remaining term	**-**	< 1 year
Forward Swaps		
Canadian dollar - notional amount[1]	**$ 2,875**	$ 3,150
Weighted forecast borrowing yields	**3.19%**	3.03%
Weighted remaining term	**1 years**	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 23.

Note 18: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

(in millions)	**2023**	2022
Restricted Cash	**$ -**	$ 6
Accounts receivable and accrued revenue	**(73)**	30
Inventories	**(106)**	(17)
Prepaid expenses	**(31)**	(15)
Other non-current assets	**25**	73
Accounts payable and accrued liabilities	**(109)**	(37)
Unearned revenues and contributions in aid	**200**	162
Post-employment benefits	**(8)**	(5)
Other non-current liabilities	**2**	(31)
	$ (100)	$ 166

Non-Cash Investing Transactions:

(in millions)	**2023**	2022
Contributions in kind received for property, plant and equipment	**$ 55**	$ 52

Reconciliation for liabilities arising from financing activities:

(in millions)	**Balance, April 1, 2022**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Proceeds (Payments)**	**Balance March 31, 2023**
Long-term debt and revolving borrowings:							
Long-term debt	$ 23,159	$ 1,498	$ (500)	$ 115	$ (15)	$ -	$ 24,257
Revolving borrowings	2,792	7,438	(7,494)	-	22	-	2,758
Total long-term debt and revolving borrowings	25,951	8,936	(7,994)	115	7	-	27,015
Lease liability (Note 19)	1,379	-	-	-	186	(117)	1,448
Vendor financing liability	313	-	-	-	20	(43)	290
Debt-related derivative liability	(179)	-	-	-	(201)	205	(175)
	$ 27,464	$ 8,936	$ (7,994)	$ 115	$ 12	$ 45	$ 28,578

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

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(in millions)	Balance, April 1, 2021	Issued	Redemptions	Foreign exchange movement	Other[1]	Proceeds (Payments)	Balance March 31, 2022
Long-term debt and revolving borrowings:							
Long-term debt	$ 22,177	$ 1,568	$ (526)	$ (40)	$ (20)	$ -	$ 23,159
Revolving borrowings	2,803	8,733	(8,744)	-	-	-	2,792
Total long-term debt and revolving borrowings	24,980	10,301	(9,270)	(40)	(20)	-	25,951
Lease liability (Note 19)	1,432	-	-	-	72	(125)	1,379
Vendor financing liability	333	-	-	-	22	(42)	313
Debt-related derivative liability	125	-	-	-	(153)	(151)	(179)
	$ 26,870	$ 10,301	$ (9,270)	$ (40)	$ (79)	$ (318)	$ 27,464

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

Note 19: Lease Liabilities

Lease costs

(in millions)	**2023**	2022
Interest on lease liabilities	**$ 46**	$ 45
Variable lease payments not included in the measurement of lease liabilities	**12**	12
Expenses relating to short-term leases and leases of low-value assets	**20**	18
	$ 78	$ 75

Amounts recognized in the statement of cash flows

(in millions)	**2023**	2022
Total cash outflow for leases	**$ 148**	$ 155

Maturity analysis

(in millions)	**March 31, 2023**	March 31, 2022
Maturity analysis - contractual undiscounted cash flows		
Less than 1 year	**$ 119**	$ 96
1 to 5 years	**443**	380
More than 5 years	**1,479**	1,462
Total Undiscounted Lease Liabilities	**$ 2,041**	$ 1,938

(in millions)	**March 31, 2023**	March 31, 2022
Current	**$ 72**	$ 52
Non-current	**1,376**	1,327
Total Lease Liabilities	**$ 1,448**	$ 1,379

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 for these long-term energy purchase agreement leases for the year ended March 31, 2023 was $10 million (2022 - $9 million). 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, 2023 was $2 million (2022 - $2 million).

Other leases
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 20: Unearned Revenues and Contributions in Aid

(in millions)	**March 31, 2023**	March 31, 2022
Unearned revenues	**$ 325**	$ 322
Contributions in aid	**2,398**	2,196
	2,723	2,518
Less: Current portion, unearned revenues	**(44)**	(40)
Less: Current portion, contributions in aid	**(64)**	(60)
	$ 2,615	$ 2,418

Note 21: 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, 2023, and March 31, 2022 was as follows:

(in millions)	**March 31, 2023**	March 31, 2022
Total debt, net of sinking funds	**$ 26,778**	$ 25,741
Less: Cash and cash equivalents	**(148)**	(99)
Net Debt	**$ 26,630**	$ 25,642
Retained earnings	**$ 7,354**	$ 6,994
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(58)**	(8)
Total Equity	**$ 7,356**	$ 7,046
Net Debt to Equity Ratio	**78 : 22**	**78 : 22**

Dividend Payment to the Province

In accordance with Order in Council No. 095/2014 from the Province, for the year ended March 31, 2018 and subsequent years, the payment to the Province was reduced by $100 million per year based on the payment in the immediate preceding fiscal year until it reached zero and will remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

As a result of the Order in Council, there was no dividend payment to the Province for the years ended March 31, 2023 and 2022.

Note 22: Post-Employment Benefits

The Company provides a defined benefit statutory (registered under the British Columbia Pension Benefits Standards Act) pension plan 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 make equal basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings as prescribed by the independent actuary. The Company may contribute additional amounts as prescribed by the independent actuary. The Company is responsible for ensuring that the 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 the 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 at December 31, 2021. The next valuation for funding purposes will be prepared no later than as at December 31, 2024, and the results will be available in September 2025.

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 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, future inflation levels impacting future salary increases 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, 2023 and 2022 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:

	Pension Benefit Plans		**Other Benefit Plans**		**Total**	
(in millions)	**2023**	2022	**2023**	2022	**2023**	2022
Current service costs charged to personnel expense - operating expenses	**$ 110**	$ 142	**$ 5**	$ 7	**$ 115**	$ 149
Net interest costs charged to finance costs	**36**	49	**8**	7	**44**	56
Total post-employment benefit plan expense	**$ 146**	$ 191	**$ 13**	$ 14	**$ 159**	$ 205

Actuarial gain recognized in other comprehensive income was $251 million (2022 – $776 million).

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

(in millions)	**Pension Benefits Plans March 31, 2023**	Pension Benefits Plans March 31, 2022	**Other Benefits Plans March 31, 2023**	Other Benefits Plans March 31, 2022	**Total March 31, 2023**	Total March 31, 2022
Defined benefit obligation of funded plan	**$ (4,980)**	$ (5,110)	**$ -**	$ -	**$ (4,980)**	$ (5,110)
Defined benefit obligation of unfunded plans	**(161)**	(160)	**(171)**	(180)	**(332)**	(340)
Fair value of plan assets	**4,581**	4,557	**-**	-	**4,581**	4,557
Plan deficit	**$ (560)**	$ (713)	**$ (171)**	$ (180)	**$ (731)**	$ (893)
Represented by:						
Accrued benefit plan liability	**$ (560)**	$ (713)	**$ (171)**	$ (180)	**$ (731)**	$ (893)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2023 and fiscal 2022 in accordance with IFRIC 14*, The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction.*

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

(in millions)	**Pension Benefit Plans March 31, 2023**	Pension Benefit Plans March 31, 2022	**Other Benefit Plans March 31, 2023**	Other Benefit Plans March 31, 2022
Defined benefit obligation				
Opening defined benefit obligation	**$ 5,270**	$ 5,684	**$ 180**	$ 217
Current service cost	**110**	142	**5**	7
Interest cost on benefit obligations	**213**	229	**8**	7
Benefits paid[1]	**(213)**	(203)	**(5)**	(5)
Employee contributions	**47**	46	**-**	-
Actuarial gains[2]	**(286)**	(628)	**(17)**	(46)
Defined benefit obligation, end of year	**5,141**	5,270	**171**	180
Fair value of plan assets				
Opening fair value	**4,557**	4,373	**n/a**	n/a
Interest income on plan assets[3]	**182**	180	**n/a**	n/a
Employer contributions	**51**	51	**n/a**	n/a
Employee contributions	**47**	46	**n/a**	n/a
Benefits paid[1]	**(204)**	(195)	**n/a**	n/a
Actuarial gains (losses)[2,3]	**(52)**	102	**n/a**	n/a
Fair value of plan assets, end of year	**4,581**	4,557	**-**	-
Accrued benefit liability	**$ (560)**	$ (713)	**$ (171)**	$ (180)

[1] Benefits paid under Pension Benefit Plans include $19 million (2022 - $21 million) of settlement payments.

[2] Actuarial gains/losses are included in the Non-Current Pension Costs Regulatory Account and for fiscal 2023 are comprised of $52 million of actuarial losses on return on plan assets (2022 - $102 million actuarial gains) and $303 million of actuarial gains (2022 - $674 million actuarial gains) on the benefit obligations mainly due to discount rate increases.

[3] Actual income on defined benefit plan assets for the year ended March 31, 2023 was $130 million (2022 - $282 million).

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(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, 2023	March 31, 2022	**March 31, 2023**	March 31, 2022
Discount rate				
Benefit cost	**4.38%**	3.40%	**4.19%**	3.14%
Accrued benefit obligation	**4.96%**	4.38%	**4.92%**	4.19%
Rate of return on plan assets	**4.38%**	3.40%	**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	**3.47%**	3.46%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**3.47%**	3.46%
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 pension plan assets are invested prudently in order to meet the Company's pension obligations. The pension plans' 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 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**		**March 31, 2023**	March 31, 2022
		Min	**Max**		
Fixed interest investments	20%	15%	35%	**20%**	24%
Public equities	40%	30%	50%	**42%**	42%
Real estate	15%	10%	20%[1]	**15%**	14%
Private equities	15%	10%	20%[1]	**15%**	12%
Infrastructure and renewable resources	10%	5%	15%[1]	**8%**	8%

[1]The total cannot exeed 50%.

Plan assets are re-balanced within ranges around target applications. The Company's expected return on plan assets is determined by considering long-term historical returns, future estimates of long-term investment returns, and asset allocations.

(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 2024 is expected to amount to $55 million. The expected benefit payments to be paid in fiscal 2024 in respect to the unfunded defined benefit plans are $14 million.

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

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(*in millions, except weighted average duration and plan participants*)		
Number of plan participants as at March 31, 2023		15,574
Actual benefit payments 2023	$	204
Benefits expected to be paid 2024	$	209
Benefits expected to be paid 2025	$	213
Benefits expected to be paid 2026	$	218
Benefits expected to be paid 2027	$	223
Benefits expected to be paid 2028	$	228
Benefits expected to be paid 2029-2032	$	969
Weighted average duration of defined benefits payments		13.9 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 two tables below present the sensitivity analysis of key assumptions for 2023.

Assumed healthcare cost trend rates have a significant effect on the amounts recognized in net income. A one percentage point change in assumed healthcare cost trend rates would have the following effects:

		2023	
(in millions)	increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Healthcare cost trend	1 % increase	$ 6	$ -
Healthcare cost trend	1% decrease	(5)	-

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

	2023		
(in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	-493	-27
Discount rate	1% decrease	+620	+37
Longevity	1 year increase	+103	+2
Longevity	1 year decrease	-106	-3
Compensation	1% increase	+157	+17
Compensation	1% decrease	-136	-14

Note 23: 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 2022/23 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 with the exception of U.S. dollar sinking funds and non-current receivables which are classified as amortized cost and carried on the consolidated statement of financial position at $237 million and $134 million, respectively. The maximum credit risk exposure for the U.S. dollar sinking funds and non-current receivables as at March 31, 2023 is their fair value of $239 million and $135 million, respectively.

(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 17). The Company's long-term debt 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 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, 2023 and 2022.

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	March 31, 2023		March 31, 2022		**2023**	2022
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	**Interest Income (Expense) recognized in Finance Charges**	Interest Income (Expense) recognized in Finance Charges
Fair Value Through Profit or Loss (FVTPL):						
Cash equivalents - short-term investments	**$ 70**	**$ 70**	$ 72	$ 72	**$ 6**	$ -
Amortized Cost:						
Cash	**78**	**78**	27	27	**-**	-
Accounts receivable and accrued revenue	**894**	**894**	802	802	**-**	-
Non-current receivables	**134**	**135**	134	140	**11**	9
Sinking funds	**237**	**239**	210	225	**10**	9
Accounts payable and accrued liabilities	**(1,953)**	**(1,953)**	(1,760)	(1,760)	**-**	-
Revolving borrowings	**(2,758)**	**(2,758)**	(2,792)	(2,792)	**(60)**	(4)
Long-term debt (including current portion due in one year)	**(24,257)**	**(22,800)**	(23,159)	(23,540)	**(814)**	(782)
First Nations liabilities (non-current portion)	**(435)**	**(467)**	(404)	(611)	**(18)**	(18)
Lease liabilities (non-current portion)	**(1,376)**	**(1,376)**	(1,327)	(1,327)	**(46)**	(45)
Other liabilities (non-current portion)	**(409)**	**(397)**	(416)	(415)	**(20)**	(21)

When the carrying value differs from fair value, the fair values of non-derivative financial instruments would be classified as Level 2 of the fair value hierarchy. The carrying value of cash equivalents, restricted cash, accounts receivable and accrued revenue, accounts payable and accrued liabilities, and revolving borrowings approximates fair value due to the short duration of these financial instruments.

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, 2023 in a net liability position of $5 million (2022 - net liability $23 million). Such contracts are used to hedge the principal on US$ 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.

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($ amounts in millions)		**March 31, 2023**		March 31, 2022
Cross- Currency Hedging Swaps				
EURO€ to CAD$ - notional amount[1]	**€**	**402**	€	402
EURO€ to CAD$ - weighted average contract rate		**1.47**		1.47
Weighted remaining term		**5 years**		6 years
Foreign Currency Hedging Forwards				
US$ to CAD$ - notional amount[1]	**US$**	**573**	US$	573
US$ to CAD$ - weighted average contract rate		**1.25**		1.25
Weighted remaining term		**7 years**		8 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, 2023 Fair Value**		March 31, 2022 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)	**$**	**29**	$	19
Foreign currency contract liabilities (cash flow hedges for US$ denominated long-term debt)		**-**		(10)
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)		**(34)**		(32)
		(5)		**(23)**
Non-Designated Derivative Instruments:				
Interest rate contract assets		**199**		180
Interest rate contract liabilities		**(24)**		(1)
Foreign currency contract liabilities		**(3)**		(4)
Commodity derivative assets		**585**		356
Commodity derivative liabilities		**(738)**		(356)
		19		175
Net asset	**$**	**14**	$	152

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

The derivatives are represented on the consolidated statement of financial position as follows:

(in millions)	**March 31, 2023**	March 31, 2022
Current portion of derivative financial instrument assets	**$ 494**	$ 315
Current portion of derivative financial instrument liabilities	**(474)**	(228)
Derivative financial instrument assets, non-current	**319**	242
Derivative financial instrument liabilities, non-current	**(325)**	(177)
Net asset	**$ 14**	$ 152

For designated cash flow hedges for the year ended March 31, 2023, there was a gain of $18 million (2022 - loss of $39 million). The effective portion was recognized in other comprehensive income. For the year ended March 31, 2023, $91 million (2022 – ($39 million)) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses (2022 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $2.88 billion (2022 - $3.73 billion), used to economically hedge the interest rates on future debt issuances, there was a $69 million increase (2022 - $230 million) in the fair value of these contracts for the year ended March 31, 2023. For interest rate contracts associated with debt issued, there was a $132 million increase (2022 - $77 million decrease) in the fair value of contracts that settled during the year ended March 31, 2023. The net increase for the year ended March 31, 2023 of $201 million (2022 - $153 million) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had an asset balance of $67 million as at March 31, 2023.

Foreign currency contracts for cash management purposes not designated as hedges, for the year ended March 31, 2023, had a loss of $1 million (2022 – gain of $2 million) recognized in finance charges. Foreign currency contracts associated with U.S. revolving borrowings not designated as hedges, for the year ended March 31, 2023, had a gain of $84 million (2022 - gain of $19 million) recognized in finance charges. These economic hedges offset $83 million of foreign exchange revaluation losses (2022 – losses of $19 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2023.

For commodity derivatives not designated as hedges, a net gain of $929 million (2022 - $785 million) was recorded in trade revenue for the year ended March 31, 2023.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2023**		2022
Deferred inception (loss) gain, beginning of the year	**$**	**(26)**	$	40
New transactions		**70**		15
Amortization		**(57)**		(82)
Foreign currency translation (gain) loss		**(2)**		1
Deferred inception loss, end of the year	**$**	**(15)**	$	(26)

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, 2023**		March 31, 2022
Current	**$**	**495**	$	425
Past due (30-59 days)		**26**		24
Past due (60-89 days)		**6**		6
Past due (More than 90 days)		**2**		3
		529		458
Less: Allowance for doubtful accounts		**(8)**		(7)
	$	**521**	$	451

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, 2023			
Derivative commodity assets	**$ 585**	**$ 9**	**$ 576**
Derivative commodity liabilities	**738**	**9**	**729**
As at March 31, 2022			
Derivative commodity assets	$ 356	$ 11	$ 345
Derivative commodity liabilities	356	11	345

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2023 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, 2023. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2023 has been used.

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(in millions)	**Carrying Value**	**Fiscal 2024**	**Fiscal 2025**	**Fiscal 2026**	**Fiscal 2027**	**Fiscal 2028**	**Fiscal 2029 *and thereafter***
Non-Derivative Financial Liabilities							
Total accounts payable and other payables	$ 1,613	$ (1,613)	$ -	$ -	$ -	$ -	$ -
(excluding interest accruals and current portion of lease obligations and First Nations liabilities)							
Long-term debt	27,244	(3,805)	(821)	(2,760)	(1,578)	(1,706)	(29,181)
(including interest payments)							
Lease obligations	1,448	(119)	(118)	(117)	(110)	(99)	(1,479)
Other long-term liabilities	884	(60)	(144)	(75)	(63)	(59)	(1,786)
Total Non-Derivative Financial Liabilities	31,189	(5,597)	(1,083)	(2,952)	(1,751)	(1,864)	(32,446)
Derivative Financial Liabilities							
Cross currency swaps used for hedging	34						
Cash outflow		(14)	(14)	(405)	(5)	(5)	(221)
Cash inflow		5	5	391	2	2	210
Other forward foreign exchange contracts designated at fair value	4						
Cash outflow		(545)	-	-	-	-	-
Cash inflow		541	-	-	-	-	-
Interest rate swaps used for hedging	24	-	(2)	(12)	(12)	-	-
Net commodity derivatives	153	(53)	(81)	(24)	(14)	(10)	4
Total Derivative Financial Liabilities	215	(66)	(92)	(50)	(29)	(13)	(7)
Total Financial Liabilities	31,404	(5,663)	(1,175)	(3,002)	(1,780)	(1,877)	(32,453)
Derivative Financial Assets							
Forward foreign exchange contracts used for hedging	(29)						
Cash outflow		-	-	(436)	-	-	(283)
Cash inflow		-	-	464	-	-	311
Other forward foreign exchange contracts designated at fair value	(1)						
Cash outflow		(112)	-	-	-	-	-
Cash inflow		113	-	-	-	-	-
Interest rate swaps used for hedging	(199)	77	100	33	-	-	-
Total Derivative Financial Assets	(229)	78	100	61	-	-	28
Net Financial Liabilities	**$ 31,174**	**$ (5,585)**	**$ (1,075)**	**$(2,941)**	**$(1,780)**	**$(1,877)**	**$ (32,425)**

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis

A $0.01 strengthening (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2023 would otherwise have a negative (positive) impact of $nil on net income before movement in regulatory balances. The Total Finance Charges Regulatory Account that captures all variances from forecasted finance charges (as described in Note 15) eliminates any impact on net income. 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, 2023 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 rates over the period until the next consolidated statement of financial position date.

(b) Interest Rate Risk

For sensitivity analysis for variable rate non-derivative instruments, an increase (decrease) of 100-basis points in interest rates at March 31, 2023 would otherwise have a negative (positive) impact on net income before movement in regulatory balance of $30 million, but as a result of regulatory accounting, it would have no impact on net income or other comprehensive income. The Total Finance Charges Regulatory Account that captures all variances from forecasted finance charges (as described in Note 15) eliminates any impact on net income. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

For the interest rate contracts, an increase of 100-basis points in interest rates at March 31, 2023 would otherwise have a positive impact on net income of $330 million and a decrease of 100 basis points in interest rates at March 31, 2023 would otherwise have a negative impact on net income before movement in regulatory balances of $400 million but as a result of regulatory accounting 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, 2023 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 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 estimates the pre-tax forward trading loss that could result from changes in commodity prices, with a specific level of confidence, over a specific time period. The Company uses an industry standard Monte Carlo VaR model to determine the potential change in value of the Company's forward trading portfolio over a 10-day holding period, within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR as an estimate of price risk has several limitations. The VaR 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 $30 million at March 31, 2023 (2022 - $61 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, 2023 and 2022:

As at March 31, 2023 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 70	$ -	$ -	$ 70
Derivatives designated as hedges	-	29	-	29
Derivatives not designated as hedges	409	218	157	784
	$ 479	$ 247	$ 157	$ 883

As at March 31, 2023 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (34)	$ -	$ (34)
Derivatives not designated as hedges	(195)	(158)	(412)	$ (765)
	$ (195)	$ (192)	$ (412)	$ (799)

As at March 31, 2022 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 72	$ -	$ -	$ 72
Derivatives designated as hedges	-	19	-	19
Derivatives not designated as hedges	255	209	74	538
	$ 327	$ 228	$ 74	$ 629

As at March 31, 2022 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (42)	$ -	$ (42)
Derivatives not designated as hedges	(141)	(65)	(157)	(363)
	$ (141)	$ (107)	$ (157)	$ (405)

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the year, commodity derivatives with a carrying amount of $6 million (2022 - $2 million) were transferred from Level 2 to Level 1.

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, 2023 and 2022:

(in millions)

Balance as at April 1, 2022	**$**	**(83)**
Net loss recognized		(232)
New transactions		56
Existing transactions settled		4
Balance as at March 31, 2023	**$**	**(255)**

(in millions)

Balance as at April 1, 2021	**$**	**(69)**
Net loss recognized		24
New transactions		(11)
Existing transactions settled		(27)
Balance as at March 31, 2022	**$**	**(83)**

During the year, no commodity derivatives (2022– no transfers) were transferred between Level 2 to Level 3.

During the year ended March 31, 2023, unrealized losses of $246 million (2022 – losses of $12 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, 2023 range between $0-$665 per MwH and a 10 percent increase/decrease in certain components of these prices would decrease/increase fair value by $41 million. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $1 million.

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Note 24: Other Non-Current Liabilities

(in millions)	**March 31, 2023**	March 31, 2022
Provisions		
Environmental liabilities	**$ 270**	$ 296
Decommissioning obligations	**70**	80
Other	**39**	31
	379	407
First Nations liabilities	**452**	419
Other contributions	**221**	225
Other liabilities	**432**	416
	1,484	1,467
Less: Current portion, included in accounts payable and accrued liabilities	**(130)**	(112)
	$ 1,354	$ 1,355

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

(in millions)	**Environmental**	**Decommissioning**	**Other**	**Total**
Balance at April 1, 2021	**$ 326**	**$ 87**	**$ 63**	**$ 476**
Made during the period	15	-	7	22
Used during the period	(46)	(4)	(26)	(76)
Changes in estimate	(4)	(5)	(13)	(22)
Accretion	5	2	-	7
Balance at March 31, 2022	**$ 296**	**$ 80**	**$ 31**	**$ 407**
Made during the period	9	-	9	18
Used during the period	(51)	(7)	(2)	(60)
Changes in estimate	9	(5)	1	5
Accretion	7	2	-	9
Balance at March 31, 2023	**$ 270**	**$ 70**	**$ 39**	**$ 379**

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, 2023, the undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2024 and 2045, is approximately $340 million and was determined based on current cost estimates. A range of discount rates between 2.9 per cent and 3.1 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 $103 million (2022 - $107 million), which will be settled between fiscal 2024 and 2053. The undiscounted cash flows, discounted by a range of discount rates between 2.9 per cent and 3.1 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 contribution from a vendor to aid in the construction of a transmission system. Contributions include payment 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 25: 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 $45.61 billion of which approximately $65 million relates to the purchase of natural gas, natural gas transportation contracts and wheeling agreements. The remaining commitments are at predetermined prices.

Included in the total value of the long-term energy purchase agreements is $1.89 billion accounted for as a lease liability under Note 19. The total BC Hydro combined payments are estimated to be approximately $1.60 billion for less than one year, $6.60 billion between one and five years, and $37.41 billion for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $6.97 billion extending to 2053. The total Powerex energy purchase commitments are estimated to be approximately $1.11 billion for less than one year, $2.92 billion between one and five years, and $2.94 billion for more than five years.

Powerex has energy sales commitments of $2.33 billion extending to 2032 with estimated amounts of $1.30 billion for less than one year, $980 million between one and five years, and $47 million 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 $1.09 billion. Included in the total value of the lease agreements is $144 million accounted for as a lease liability under Note 19. Payments are $55 million for less than one year, $168 million between one and five years, and $866 million for more than five years.

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 unfavourably 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. It is not possible at this time to predict with any certainty the outcome of such litigation. Management believes that any 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 $0.13 billion (2022 - $1.36 billion). The 2022 comparative figure include amounts provided by the Company to secure pension plan solvency deficiency payments related to the registered pension plan, which was no longer required in 2023. The total outstanding letters of credit also includes US $20 million (2022 - US $15 million) in foreign denominated letters of credit.

Note 26: 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 an energy marketer, whose activities include trading wholesale power, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), natural gas, ancillary services, and financial 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.

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The related party transactions are summarized below:

(in millions)	**March 31, 2023**	March 31, 2022
Consolidated Statement of Financial Position		
Prepaid expenses	**$ 109**	$ 101
Right-of-use assets	**1,204**	1,217
Accounts payable and accrued liabilities	**112**	78
Lease liabilities	**1,342**	1,344

	2023	2022
Amounts incurred/accrued during the year include:		
Water rental fees	**358**	345
Cost of energy	**419**	263
Grants and Taxes	**159**	152
Interest	**874**	786
Derivatives	**(287)**	162
Lease payments	**102**	100
Other	**75**	111

The Company's debt is either held or guaranteed by the Province (see Note 17). 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, 2023, the aggregate exposure under this indemnity totaled $229 million (2022 - $201 million).

The Company has not experienced any losses to date under this indemnity.

The Site C Project requires the realignment of six segments of Highway 29 with a total length of approximately 30 kilometers. The highway re-alignment activities are needed for reservoir inundation which is required prior to the first generating unit in service forecasted for December 2024. The Province (Ministry of Transportation and Infrastructure) maintains effective control over the highway during the re-alignment activities and after these activities are complete. During fiscal year 2023, BC Hydro incurred total costs of approximately $103 million (2022 – $190 million) on highway re-alignment activities, of which $61 million (2022 - $104 million) was paid directly to the Province. As of March 31, 2023, all six segments of Highway 29, including the new bridges, have been opened to traffic and are being operated by the Ministry of Transportation and Infrastructure.

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 through a public auction 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)	**2023**	2022
Short-term employee benefits	**$ 5**	$ 4
Post-employment benefits	**2**	2

Appendix D: Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2023**	2022[1]	2021	2020[2]	2019[3]
Revenues					
Domestic	**$ 5,304**	$ 5,619	$ 5,237	$ 5,393	$ 5,432
Trade	**2,723**	1,972	1,177	876	1,144
	8,027	7,591	6,414	6,269	6,576
Expenses					
Domestic energy costs	**1,672**	1,936	1,690	1,681	1,557
Trade energy costs	**1,451**	1,066	579	689	624
Other operating expenses[4]	**1,538**	1,427	1,366	1,372	1,292
Amortization and depreciation	**1,052**	1,079	1,009	988	949
Grants and taxes	**296**	286	254	254	266
Finance charges	**496**	521	224	1,666	1,196
	6,505	6,315	5,122	6,650	5,884
Net Income (Loss) Before Movement in Regulatory Balances	**1,522**	1,276	1,292	(381)	692
Net movement in regulatory balances	**(1,162)**	(608)	(604)	1,086	(1,120)
Net Income (Loss)	**$ 360**	$ 668	$ 688	$ 705	$ (428)
Property, Plant and Equipment, Right-of-Use Assets and Intangible Assets					
Property, Plant and Equipment	**$ 36,926**	$ 34,038	$ 31,677	$ 29,427	$ 27,334
Right-of-Use Assets	**1,305**	1,248	1,317	1,405	1,466
Intangible Assets	**639**	640	688	678	602
Net Book Value	**$ 38,870**	$ 35,926	$ 33,682	$ 31,510	$ 29,402
Property, Plant and Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,211**	$ 1,119	$ 971	$ 955	$ 965
Growth	**2,708**	2,356	2,236	2,127	2,861
Total Property, Plant and Equipment and Intangible Asset Expenditures [5]	**$ 3,919**	$ 3,475	$ 3,207	$ 3,082	$ 3,826
Net Long-Term Debt [6]	**$ 26,630**	$ 25,642	$ 24,740	$ 23,354	$ 22,101
Retained Earnings	**$ 7,354**	$ 6,994	$ 6,326	$ 5,638	$ 4,933
Debt to Equity Ratio	**78 : 22**	78 : 22	80 : 20	81 : 19	82 : 18

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

2 In 2019/20, certain amounts have been reclassified to conform to the 2020/21 presentation.

3 The Company adopted IFRS 16, *Leases* (IFRS 16) in 2019/20 and restated the comparative periods 2018/19. For additional information, refer to Note 27: Explanation of Adoption of IFRS 16 in the Audited Financial Statements within the 2019/20 Annual Service Plan Report.

4 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.

5 Total property, plant and equipment, and intangible asset expenditures are different from the amount of property, plant and equipment, and intangible asset expenditures in the Consolidated Statements of Cash Flows due to the effect of accruals related to these expenditures.

6 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	**2023**	2022	2021	2020[1]	2019
Generating Capacity (megawatts)					
Hydroelectric	**12,041**	12,027	12,027	11,932	11,932
Thermal	**174**	179	177	177	177
Total	**12,215**	12,206	12,204	12,109	12,109
Peak One-Hour Integrated System Demand (megawatts)	**10,977**	10,787	10,076	10,577	10,045
Number of Domestic Customer Accounts					
Residential	**1,961,208**	1,931,041	1,896,518	1,863,569	1,833,097
Light industrial and commercial	**223,915**	221,573	218,196	215,063	212,446
Large industrial	**203**	201	202	198	195
Other	**3,367**	3,387	3,383	3,396	3,419
Total	**2,188,693**	2,156,202	2,118,299	2,082,226	2,049,157
Domestic Electricity Sold (gigawatt-hours)					
Residential	**19,547**	19,440	18,983	17,993	18,000
Light industrial and commercial	**19,247**	19,029	18,091	18,692	19,007
Large industrial	**13,437**	13,312	12,438	13,398	13,896
Surplus Sales	**-**	-	-	-	2,230
Other sales	**2,028**	1,671	1,628	1,848	1,510
Total	**54,259**	53,452	51,140	51,931	54,643

Revenues (in millions)

for the years ended March 31	**2023**	2022	2021	2020[1]	2019[2]
Residential	**$ 2,146**	$ 2,342	$ 2,210	$ 2,169	$ 2,127
Light industrial and commercial	**1,840**	1,952	1,830	1,942	1,925
Large industrial	**848**	854	762	850	873
Surplus Sales	**-**	-	-	-	115
Other sales	**470**	471	435	432	392
Total Domestic	**5,304**	5,619	5,237	5,393	5,432
Trade	**2,723**	1,972	1,177	876	1,144
Total	**$ 8,027**	$ 7,591	$ 6,414	$ 6,269	$ 6,576

Average Revenue (per kilowatt-hour)

for the years ended or as at March 31	**2023**	2022	2021	2020	2019
Residential	**11.0¢**	12.0¢	11.6¢	12.1¢	11.8¢
Light industrial and commercial	**9.6**	10.3	10.1	10.4	10.1
Large industrial	**6.3**	6.4	6.1	6.3	6.3
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**10,044**	10,158	10,097	9,735	9,899
Lines In Service					
Distribution (kilometres)	**60,289**	60,093	59,907	59,694	59,095
Transmission (circuit kilometres)	**20,192**	20,148	19,958	20,389	20,385

1 BC Hydro entered into a new energy Transfer Pricing Agreement with Powerex in 2020/21 replacing a previous agreement which was established in
As a result, the comparative period 2019/20 was restated for presentation changes between domestic and trade revenue and cost of energy ($ and GwH).

2 The Company adopted IFRS 16, *Leases* (IFRS 16) in 2019/20 and restated the comparative periods 2018/19. For additional information, refer to Note 27: Explanation of Adoption of IFRS 16 in the Audited Financial Statements within the 2019/20 Annual Service Plan Report.

TOTAL ELECTRICITY SALES AND SOURCES OF SUPPLY

for the years ended March 31	**2023**			2022			2021			2020[2]			2019		
	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	**12,215**	**54,259**	**70.5**	12,206	53,452	70.3	12,204	51,140	67.6	12,109	51,931	73.2	12,109	54,643	74.6
Electricity trade[1]		**17,639**	**22.9**		17,836	23.5		19,407	25.7		14,346	20.2		14,139	19.3
		71,898	**93.4**		71,288	93.8		70,547	93.3		66,277	93.4		68,782	93.9
Line loss and system use		**5,118**	**6.6**		4,709	6.2		5,104	6.7		4,651	6.6		4,496	6.1
		77,017	**100.0**		75,997	100.0		75,651	100.0		70,928	100.0		73,278	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,857**	**13,497**	**17.5**	2,857	15,626	20.6	2,857	15,907	21.0	2,778	12,605	17.8	2,778	11,634	15.9
Revelstoke	**2,480**	**9,410**	**12.2**	2,480	8,548	11.2	2,480	9,218	12.2	2,480	7,286	10.3	2,480	8,408	11.5
Mica	**2,746**	**8,733**	**11.3**	2,746	7,681	10.1	2,746	8,669	11.5	2,746	6,262	8.8	2,746	7,625	10.4
Kootenay Canal	**583**	**2,300**	**3.0**	583	2,780	3.7	583	2,626	3.5	583	2,377	3.4	583	2,486	3.4
Peace Canyon	**694**	**3,319**	**4.3**	694	3,791	5.0	694	3,893	5.1	694	3,051	4.3	694	2,938	4.0
Seven Mile	**805**	**2,906**	**3.8**	805	2,936	3.9	805	3,039	4.0	805	2,842	4.0	805	3,137	4.3
Bridge River	**491**	**2,588**	**3.4**	478	2,578	3.4	478	2,219	2.9	478	2,367	3.3	478	1,996	2.7
Other	**1,385**	**3,384**	**4.4**	1,384	4,125	5.2	1,384	4,225	5.6	1,368	3,592	5.1	1,368	4,118	5.5
	12,041	**46,137**	**59.9**	12,027	48,065	63.1	12,027	49,796	65.8	11,932	40,382	57.0	11,932	42,342	57.7
Thermal generation	**174**	**175**	**0.2**	179	125	0.2	177	150	0.2	177	172	0.2	177	190	0.3
Purchases under long-term commitments		**15,408**	**20.0**		16,824	22.1		14,630	19.3		14,474	20.4		14,248	19.4
Purchases under short-term commitments		**117**	**0.2**		119	0.2		109	0.1		110	0.2		103	0.1
Electricity trade purchases		**16,005**	**20.8**		11,857	15.6		11,321	15.0		16,371	23.1		16,550	22.6
Other		**(826)**	**(1.1)**		(993)	(1.3)		(355)	(0.5)		(581)	(0.8)		(155)	(0.2)
	12,215	**77,017**	**100**	12,206	75,997	99.9	12,204	75,651	100.0	12,109	70,928	100.0	12,109	73,278	100.0

[1]Electricity trade represents electricity sold that is surplus to domestic load requirements and other sales that are outside the Province of British Columbia.

[2]BC Hydro entered into a new energy Transfer Pricing Agreement with Powerex in 2020/21 replacing a previous agreement which was established in 2002/03. As a result, the comparative period 2019/20 was restated for presentation changes between domestic and trade revenue and cost of energy ($ and GwH).