British Columbia Hydro and Power Authority

2019/20
Annual Service Plan Report

For more information on BC Hydro contact:

333 Dunsmuir Street
Vancouver, BC
V6B 5R3

Lower Mainland

604 BCHYDRO
(604 224 9376)

Outside Lower Mainland
1 800 BCHYDRO
(1 800 224 9376)

Or visit our website at
bchydro.com

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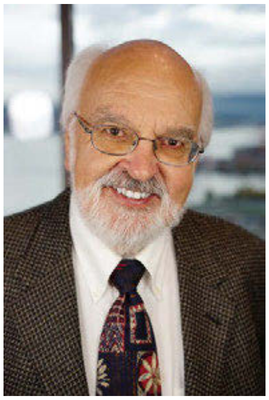
Board Chair's Accountability Statement



BC Hydro is a provincial Crown Corporation, owned by the people of British Columbia. We operate an integrated system of generation, transmission and distribution infrastructure to safely provide reliable, affordable and clean electricity to our customers throughout British Columbia. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

The Board and Management are accountable for the contents of this report and how it is reported. The Board is also responsible for ensuring internal controls are in place to measure information and report accurately and in a timely fashion.

All significant assumptions, policy decisions, events and identified risks, as of March 31, 2020 have been considered in preparing the report. The report contains estimates and interpretive information that represent the best judgment of management. Any changes in mandate direction, goals, strategies, measures or targets made since the 2019/20 - 2021/22 Service Plan was released and any significant limitations in the reliability of the information are identified in the report.

The *BC Hydro 2019/20 Annual Service Plan Report* compares the corporation's actual results to the expected results identified in the *2019/20 – 2021/22 Service Plan* created in February 2019. The Board is accountable for those results as reported.

Kenneth G. Peterson
Board Chair

Table of Contents

Letter from the Board Chair & President & 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, 2020. 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.

Clean, reliable and affordable electricity is vital to British Columbia's economic prosperity and our quality of life. BC Hydro continues to invest in our system to ensure it is there to support British Columbia's growing population and economy. We are investing approximately $3 billion per year to upgrade aging assets and build new infrastructure so that our customers continue to receive reliable and clean electricity.

We have the important responsibility to keep electricity rates affordable for our customers, while funding necessary investments in our electricity system. To support this goal, we implemented the outcomes from Phase 1 of the Comprehensive Review of BC Hydro and continued to make all reasonable efforts to limit rate increases. We have also advanced affordability initiatives to help our customers save money on their electricity bills and continued to focus on making it easier for our customers to do business with us.

We are working with the Province on Phase 2 of the Comprehensive Review to strategically position BC Hydro for long-term success, while meeting the Province's climate goals, keeping rates affordable for British Columbians, furthering reconciliation with Indigenous Peoples and supporting quality economic development. The actions taken as part of the Phase 2 Review will support the government's CleanBC plan, including expanding the electrification of our growing economy over the coming decades.

BC Hydro worked closely with the Ministry of Energy, Mines and Petroleum Resources to ensure alignment with government policy expectations through regular meetings and updates. These were held between the Executive, the Minister and his staff and the Board Chair, as appropriate, to discuss actions identified in the Board Chair's Mandate Letter. With respect to organizational governance and shareholder engagement, the development and responsibilities of Directors and the Executive are outlined in Appendix A: Additional Information.

We're proud of our accomplishments this year. We will continue to work together to ensure that our workforce goes home safely, every day, while delivering clean, reliable and affordable electricity to our customers.

Kenneth G. Peterson Board Chair	Chris O'Riley President and Chief Executive Officer

Purpose of the Annual Service Plan Report

The Annual Service Plan Report is designed 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, the Crown Corporation's Board is required to report on the actual results of the Crown's performance related to the forecasted targets documented in the previous year's Service Plan.

Purpose of the Organization

BC Hydro's mission is to safely provide our customers with reliable, affordable and clean electricity throughout British Columbia. 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 78,000 kilometres of transmission and distribution lines. Our partnership with B.C.'s clean energy industry encompasses approximately 120 projects across the province, including biomass, hydro, wind and solar generating facilities. Our electricity generation is 96.3 per cent clean.

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 Energy, Mines and Petroleum Resources and the Government's expectations are expressed through the annual Mandate Letter to the Board Chair 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

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 providing research and development, testing, technical services and advanced technology services to clients around the world, including BC Hydro. For more information on Powerex, Powertech and other active and inactive subsidiaries, see *Appendix B: Subsidiaries and Operating Segments*.

Strategic Direction

The strategic direction set by Government in 2019/20 and expanded upon in the Board Chair's Mandate Letter from the Minister Responsible in 2019 shaped the 2019/20 – 2021/22 BC Hydro Service Plan and results reported in this annual report.

BC Hydro is aligned with the Government's key priorities:

Government Priorities	BC Hydro aligns with these priorities by:
Making life more affordable	• Ensuring our customers will benefit from affordable bills while managing our costs, exploring innovative solutions to support our customers and making investments to maintain and expand our electricity system. (Objective 3.1)
Delivering the services people count on	• Reliably meeting the electricity requirements of customers and responding to their evolving expectations by planning and investing in the system to meet future needs and by consistently improving our service. (Objective 2.1)
A strong, sustainable economy	• Continuing to implement the updated 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity. (Strategy under Objective 3.1) • Supporting the implementation of the CleanBC plan to increase British Columbians' use of cleaner energy in key sectors of the economy and shift away from reliance on fossil fuels for transportation, industry and housing. (Strategy under Objective 4.1)

Operating Environment

As a utility that operates in a high hazard industry, safety is always top of mind and we are continuously working to improve our performance by understanding hazards, ensuring appropriate design of assets, related work procedures and competencies. Our goal continues to be that everyone goes home safely, every day.

We continued to implement a number of strategies resulting from Phase 1 of the Comprehensive Review by continuing to make reasonable efforts to limit rate increases and manage our costs. We worked with the Province on Phase 2 of the Comprehensive Review to strategically position BC Hydro for long-term success, while furthering reconciliation with Indigenous Peoples and supporting quality economic development. The actions taken as part of the Phase 2 Review will support the government's CleanBC plan, including expanding the electrification of our growing economy over the coming decades, while keeping rates affordable for our customers.

British Columbia experienced a severe snowstorm in the Southern Interior starting on December 31, 2019, causing extensive damage to BC Hydro infrastructure. The storm caused more than 160,000 customers in the region to lose power. BC Hydro crews worked to repair over 130 spans of wire and damage to poles, cross-arms and transformers to restore power to our customers. Two weeks later, a windstorm on Vancouver Island and the South Coast also caused damage to BC Hydro infrastructure, leading to power outages for customers. High winds and snow caused branches and trees to fall onto power lines and, at the peak of the storm, approximately 30,000 customers were without power.

BC Hydro is proud of how our company responded and the quick restoration of service to the majority of our customers during these storms. Despite poor weather and treacherous road conditions in the Central and Southern Interior creating challenges for crews, more than 60 per cent of customers had power restored within the first 24 hours, and 90 per cent in 48 hours. Similarly, after the windstorms on Vancouver Island and South Coast, the majority of affected customers had service restored within 24 hours. These storm events allowed us to test a number of new processes we established following the December 2018 windstorm. Some of the improvements were focused on how we get information back to our customers. Timely, regular and accurate information about outages is becoming more important to our customers and the communities we support.

We saw record peak electricity consumption this winter. On January 14, 2020, BC Hydro set a new record for power consumption when demand peaked at 10, 577 megawatts (MW), the highest in our history. We are fortunate to have a large, flexible system that enables us to respond to increased electricity demand, which means that the power will be there on the coldest, darkest days, as we experienced this winter.

We successfully managed our reservoir system and inflows throughout the year, in various weather conditions, to continue to meet our customers' electricity needs. 2019/20 began with below average reservoir levels in the coastal and Williston basins, but with thoughtful planning, BC Hydro incrementally recovered levels during the summer months. We continued to provide reliable and flexible power during the winter, including meeting several record winter peak loads. We also managed our coastal system through some of the driest and wettest weather sequences on record, in November 2019 and January 2020, respectively.

In March 2020, the British Columbia government declared a provincial state of emergency to support the province-wide response to the novel coronavirus (COVID-19) pandemic. BC Hydro responded quickly, recognizing the critical role we have as an essential service to deliver safe, reliable power in the province. We filed a Pandemic Response Plan with the BC Utilities Commission (BCUC) that outlined how BC Hydro would maintain critical and supporting functions during the outbreak. Our strategy focused on the following priorities: slowing the spread of the virus by implementing measures to protect our facilities, employees and the public guided by the advice of provincial health authorities; redeploying resources and focusing on essential work such as keeping the lights on for customers and keeping the public safe; safely advancing Site C diversion on schedule; maintaining physical and cyber security and communicating proactively with employees. To help our customers, we introduced a COVID-19 Customer Assistance Program to provide them with the option to defer payments, or arrange a flexible payment plan to help pay their BC Hydro bills.

These external events had the potential to affect BC Hydro's performance. However, due to thoughtful planning and prudent decision-making, BC Hydro managed each risk and continued to safely deliver clean, reliable and affordable electricity throughout B.C.

Report on Performance: Goals, Objectives, Measures and Targets

BC Hydro continued to focus on achieving the objectives outlined in the Board Chair's Mandate Letter and aligning to Government's key commitments to British Columbians: making life more affordable, delivering the services people count on and building a strong sustainable economy.

BC Hydro's mission is to safely provide our customers with reliable, affordable, clean electricity throughout B.C. We have continued to implement our strategies to achieve our four goals and 12 performance measures as set out in the 2019/20 – 2021/22 Service Plan. The goals and measures below track our progress on delivering the identified priorities for 2019/20.

BC Hydro management is responsible for measuring performance against targets, and results are reported to the Board on a quarterly basis, and publicly in the Annual Service Plan Report.

Goal 1: Safety Above All

Objective 1.1: Safety at BC Hydro is a core value. We are committed to ensuring our workforce goes home safely every day, and that the public is safe around our system.

Key Highlights

- As of March 31, 2020, BC Hydro had gone 3,515 days without a fatality - the longest period without a fatality in over 30 years of recorded data.
- Ninety-eight per cent of corrective actions resulting from safety incident reviews were completed within 30 days of the due date compared to a target of ninety-five per cent.
- Updated our number one life saving rule, the Limits for Approach, for consistency in application across the organization and alignment with industry standards.

Performance Measure(s)[1]	2018/19 Actuals	2019/20 Target	2019/20 Actuals	2020/21 Target	2021/22 Target
1.a Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0	0	0	0	0
1.b Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	0.87	0.80	0.93	0.80	0.75[3]
1.c Timely Completion of Corrective Actions (%)	98	95	98	97[4]	97

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at http://www.bchydro.com/performance.
[2] Zero Fatality and Serious Disabling Injury – BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.
[3] The 2021/22 Lost Time Injury Frequency 2021/22 target was adjusted from 0.75 to 0.76 in the 2020/21 – 2022/23 Service Plan.
[4] The 2020/21 Timely Completion of Corrective Actions' target was adjusted from 95 per cent to 97 per cent in the 2020/21 – 2022/23 Service Plan.

Discussion of Results

Overall in 2019/20, we made good progress in meeting some of our safety targets; however, more work needs to be done as we continue to see near misses involving electricity that could have seriously injured our employees. We are in the last year of implementing our five-year safety plan.

BC Hydro's investments in safety initiatives have improved our safety performance to zero fatalities since 2010. To reduce electrical contract injuries, we revised the Limits for Approach rule – the closest distance an Authorized Worker is permitted to approach exposed energized conductors or equipment – for consistency in application across the organization and to align BC Hydro with industry standards. The revisions were introduced to our workforce as part of the new Safety Practices Regulation book, released in February 2020.

We finished 2019/20 with a lost time injury frequency rate of 0.93 compared to a target of 0.80. There were 52 lost time injuries attributed to slips, trips and falls and a small number of motor vehicle and electrical contacts incidents. In the months prior to November 2019, the lost time injury frequency rate was trending towards the target of 0.80. However, we experienced an abnormally high number of lost time injuries in November.

In 2020/21, we will work to improve performance through continued focus on controlling safety risks and mitigating safety hazards, sustain the ergonomics program that helps to mitigate body mechanic incidents and encourage timely utilization of the Return to Work/Stay at Work program. We anticipate that the completion of the three year ergonomic program in 2021/22 will result in a 50 per cent reduction of ergonomic injuries, which should reflect a measurable net decrease in lost time injury frequency.

In 2019/20, 98 per cent of the corrective actions were completed within 30 days of the due date compared to a target of 95 per cent, as we continue focusing on meeting the due dates of these important action plans that help address systemic safety issues and risks. The primary drivers for exceeding our target were: the corrective action governance team which supports the creation and implementation of complex corrective actions; the incident review calls between senior management and the responsible manager to further support the creation of better corrective actions while also identifying and addressing systemic issues; and continued leadership focus on ensuring corrective actions are completed in a timely manner.

We continued work on an integrated Safety and Compliance Framework to provide a structured, consistent and disciplined approach for managing both safety and compliance risks across BC Hydro. 2019/20 contributions to the framework include documenting safety standards, defining regulatory requirements for functional roles and establishing the hazard assessment processes.

Goal 2: Set the Standard for Reliable and Responsive Service

Objective 2.1: BC Hydro will reliably meet the electricity requirements of customers and respond to their evolving expectations by planning and investing in the system to meet future needs and by consistently improving our service.

Key Highlights

- Targets for our customer reliability measures, System Average Interruption Duration Index and System Average Interruption Frequency Index, were met despite facing multiple weather events throughout the year.
- Customer Satisfaction Index increased one per cent compared to our 2018/19 results, with improvements across all three customer segments: residential, commercial and key accounts.
- Continued to demonstrate progress in leading practices in Indigenous relations by implementing our comprehensive Indigenous awareness training for employees.

Performance Measure(s)[1]	2018/19 Actuals	2019/20 Target	2019/20 Actuals	2020/21 Target	2021/22 Target
2.a SAIDI (System Average Interruption Duration Index)[2] [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year (excluding major events)]	2.96	3.25	3.08	3.20	3.20
2.b SAIFI (System Average Interruption Frequency Index)[2] [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.35	1.40	1.48	1.40	1.40
2.c Key Generating Facility Forced Outage Factor (%)[3]	1.61	1.80	1.69	1.80	1.80
2.d CSAT Index[4] [Customer Satisfaction Index: % of customers satisfied or very satisfied]	87.7	85.0	88.8	85.0	85.0
2.e Progressive Aboriginal Relations (PAR) Designation[5]	Gold	Gold	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.

[2] Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the reliability projection modelling uncertainty, the wide range of variations in weather patterns and the uncontrollable elements that can significantly disrupt the electrical system. BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is 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.

[3] Key Generating Facility Forced Outage Factor is reported as a five year rolling average and defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year).

[4] Customer Satisfaction Index (CSAT) is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial and key accounts). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.

[5] The Canadian Council for Aboriginal Business' mission is to foster sustainable business relations between First Nations, Inuit and Métis people and Canadian Business. It assesses performance in Leadership Actions, Community Relations, Employment & Business Development. Committing to the PAR program helps companies assess and improve their Indigenous relations policies, strategies and actions and signals to communities that they are committed to prosperity in Indigenous communities. BC Hydro was recertified at the gold level for three years in 2018/19.

Discussion of Results

Reliability

Customer reliability is measured using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). This year, we experienced multiple weather events below the threshold for major storm events and continued to meet our reliability targets. We maintained our reliability performance by effectively implementing capital and maintenance programs to manage overall asset health, targeting the worst performing circuits and developing well-practiced emergency response plans.

In 2019/20 BC Hydro:

- Targeted deployment of automated reclosers and switches to reduce sustained customer outages.
- Continued improvement in outage data analytics to target the circuits in need of reliability enhancement.
- Focused on keeping customers impacted by planned work on the system to a minimum by increased switching to alternate supply and a monthly review of plans.
- Completed a review and upgrade of our security services and systems to streamline work, reduce costs and increase efficiency.
- Tested our earthquake response capacity using more than 35 emergency plans for a large seismic event to increase our organizational resiliency.

BC Hydro continues to report on the Key Generating Facility Forced Outage Factor as an important measure of the ongoing reliability of the generating system. There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200 MW[1]. Together, they provide 90 per cent of the average annual electricity generated by BC Hydro's facilities. This measure demonstrates the continued effectiveness of BC Hydro's maintenance and capital investment programs.

[1] The Waneta Generating Station is not included in the Forced Outage Factor Performance Measure because BC Hydro does not manage or operate the facility.

In 2019/20, BC Hydro continued to focus on the following to ensure the reliability of the Key Generating Facilities:

- Leveraging condition monitoring and predictive maintenance techniques to detect and diagnose asset performance issues to proactively prevent unplanned downtime and increase asset availability.
- Returning equipment at Key Generating facilities to service in a timely manner, to minimize the duration of an outage and the impacts on the power system.
- Undertaking formal investigations to ensure that the root causes of a failure are established. Where applicable, maintenance and predictive analytics programs are modified and applied across the entire fleet of assets. Training and processes on root cause analysis were enhanced to prevent or mitigate similar outages in the future.
- Giving priority to Key Generating facilities as part of our overall capital plan to ensure their ongoing reliability.

BC Hydro achieved the target to remain below 1.80 percent for Key Generating Facility Forced Outage Factor with a result of 1.69 per cent.

Service

The Customer Satisfaction Index (CSAT) measure gauges the level of customer support in meeting their electricity needs. Our 2019/20 CSAT result of 88.8 per cent, an improvement over the previous three years, reflects our ongoing efforts in ensuring high customer reliability, continued commitment to customer service and improvements in our customer communications. In 2019/20 BC Hydro:

- Continued to make improvements to customer service functions that had previously been outsourced. In the second year of operations after repatriation of those functions:
  - Training and process changes were initiated to increase the focus on resolving customers' issues;
  - Escalations within the contact centre decreased 24 per cent as compared to 2018/19; and,
  - First contact resolution averaged 75 per cent as compared to a target of 73 per cent.
- Implemented changes to outage communications and restoration to improve the availability and accuracy of restoration times to customers impacted by large storms.
- For Transmission Service customers:
  - Implemented a pilot to expand the availability of market-based rates for incremental consumption year-round;
  - Continued focus on supporting customers through the process of siting and interconnecting their facilities; and,
  - Replaced the billing system and implemented a new bill design.
- Enabled electronic payments for customers requiring design and connection services, and worked with business customers to improve processes for electricity payments through Electronic Funds Transfer.

- Expanded the number of Electric Vehicle (EV) chargers from 60 to 82, at 72 different sites. Also continued to improve uptime of charging stations by enhancing inspection and support models.
- Launched a new EV fast charging station design and web platform with a focus on customer experience, reliability and safety. Features include updated station design, lighting, signage, mobile app, web portal and customer support. In recognition of developing EV station experience best practice, BC Hydro received the ESource 2019 Customer Design Award for this innovation.
- Increased the level of proactive customer engagement for BC Hydro’s work programs (e.g., voltage conversions) and planned outages.
- Continued the second year of the three-year Customer Crisis Fund Pilot. In 2019/20, 3,273 customers facing disconnection received grants totaling $1.24 million to enable the continued supply of electricity.

Indigenous Relations

With the historic passing of the *Declaration on the Rights of Indigenous Peoples Act* in November 2019, BC Hydro is working to implement the United Nations Declaration on the Rights of Indigenous Peoples, the Calls to Action of the Truth and Reconciliation Commission and the Draft Principles that Guide the Province of British Columbia’s Relationship with Indigenous Peoples into its business.

In 2018/19, BC Hydro obtained our third consecutive Gold level certification, valid for a three-year period, under the Progressive Aboriginal Relations program from the Canadian Council of Aboriginal Business demonstrating our progress to implement leading 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 designation level. BC Hydro has continued to advance its approach, programs and support for Indigenous communities.

In 2019/20, BC Hydro continued to demonstrate progress in leading practices in Indigenous relations by:

- Implementing our comprehensive Indigenous awareness training, a foundational 30 minute e-learning module and 4-hour in-person course, for employees. To date, over 1,600 employees have completed the 30 minute web-based training and over 1,000 people have taken the in-person training facilitated by Indigenous employees.
- Piloting a new Try-A-Trade Program for Indigenous candidates interested in exploring several trades through an eight-week work experience program. The program will now be offered annually.

BC Hydro continues to seek to develop and sustain positive long-term relationships and better understand Indigenous interests so that their priorities are recognized in our capital projects, programs and operations activities. This year, BC Hydro:

- Provided over $150 million in contract opportunities to Indigenous designated businesses.

- Continued to provide Indigenous people with employment on our capital projects. For example, the Site C project contractors employed between 283 and 428 Indigenous people (9-11 per cent of the contractor workforce) during 2019/20.
- Hired 20 Indigenous employees for roles on various teams throughout the company, including Safety, Engineering, Apprenticeship, Customer Service and work experience programs related to trades and career exploration. Additionally, 26 scholarships and bursaries were awarded to Indigenous students pursuing post-secondary studies, and BC Hydro worked with over 150 candidates through outreach and skill building/training.

Goal 3: Help Keep Electricity Affordable for our Customers

Objective 3.1: BC Hydro customers will benefit from affordable bills while we manage our costs, explore innovative solutions to support our customers, and make investments to maintain and expand our electricity system.

Key Highlights

- BC Hydro residential rates were again ranked in the first quartile for 2019/20, based on analysis of Hydro Quebec's annual report, 2019 Comparison of Electricity Rates in Major North American Cities.
- Filed an update to our Fiscal 2020 to Fiscal 2021 Revenue Requirements Application requesting an approximately 1 per cent rate decrease, effective April 1, 2020, approved by the BCUC on an interim basis.
- Over the last five years, BC Hydro successfully delivered 377 capital projects at a total cost of $7.02 billion, which is 2.23 per cent under budget overall and within the target of +/- 5 per cent of budget.

Performance Measure(s)[1]	2018/19 Actuals	2019/20 Target	2019/20 Actuals	2020/21 Target	2021/22 Target
3.a Affordable Bills[2]	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile
3.b Project Budget to Actual Cost[3]	+0.34% on $8.03 billion[4]	Within +5% to -5% of budget excluding project reserve amounts	-2.23% on $7.02 billion[5]	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] BC Hydro calculates a relative index for each usage level within the residential category and then calculates an average of the index to create an overall ranking based on Hydro Quebec's annual report on North American electricity rates. The rankings of the 22 participating utilities are then allocated into quartiles. The 1st quartile ranking represents the six utilities that have the lowest monthly electricity bills on April 1 of a given year.
[3] 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.
[4] This represents projects that went into service for the five-year period 2014/15 to 2018/19.
[5] This represents projects that went into service for the five-year period 2015/16 to 2019/20.

Discussion of Results

BC Hydro prudently manages all costs to maintain affordable rates for our customers, including operating and capital expenditures. Our ongoing actions to keep rates low for our customers have resulted in our residential rates again being ranked in the first quartile (third overall) for 2019/20, based on analysis of Hydro Quebec's annual report, 2019 Comparison of Electricity Rates in Major North American Cities.

In August 2019, BC Hydro filed an update to our Fiscal 2020 to Fiscal 2021 Revenue Requirements Application requesting an approximately 1 per cent rate decrease, effective April 1, 2020, to help keep our customers' electricity bills affordable.

In addition, BC Hydro began analyzing a number of potential rate design options as outlined in the Comprehensive Review of BC Hydro: Phase 2 Interim Report that will help make customers' electricity bills more affordable and support the implementation of the CleanBC plan.

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, less project reserve funds. In the last five years, BC Hydro successfully delivered 377 capital projects at a total cost of $7.02 billion, which is 2.23 per cent under budget overall and within the target of +/- 5 per cent of budget. During 2019/20, capital projects placed in-service totaled $1.2 billion, including Bridge River 2 Units 5 & 6 Upgrade, Cheakamus Units 1 & 2 Generator Replacement, Mica Powerhouse Cranes Upgrade and Cheakamus Units 1 & 2 Turbine Upgrade.

In 2019/20, BC Hydro's Project Delivery group actively managed approximately 300 projects, with a combined portfolio value of approximately $7 billion. We continued to improve our project and portfolio performance reports, including a data analytics initiative to better leverage historical project delivery information to support decision-making and timely delivery of projects within budget. We also implemented scalable project management practices to applicable projects.

In 2019/20, we advanced additional initiatives to improve our processes and supply chain strategies:

- Continued to focus on our Work Smart program, which improves our processes by employing Lean and other methodologies, and undertook 20 projects and initiatives across the company in 2019/20. These projects and initiatives, in which employees are empowered to develop and implement enhanced processes through a structured framework, are estimated to generate at least 15,000 capacity hours of staff effort which can be applied to other priorities or initiatives.
- Continued to implement the Supply Chain Applications project which will provide technology and new business processes to help achieve the capabilities needed to fully operationalize the Supply Chain business model.
- Progressed with Category Management implementation, which continues to be on track. Category Management incorporates strategy development, business process improvements, sourcing, contract management and supplier management. There are 37 active categories/subcategories that have generated benefits through cost avoidance and additional savings.

Construction on the Site C project has been underway since July 2015. As of March 31, 2020, the project had contractual commitments of $7.9 billion, of which $5.1 billion has been spent since the project began and $2.8 billion remains on executed contracts and agreements. Key accomplishments this year included:

- **Construction activities:** Over the last year, we safely achieved several critical construction milestones, and advanced our agreements with communities and First Nations.

  We successfully reached a major project milestone with the completion of the excavations for our two diversion tunnels in December 2019. These tunnels will be used to reroute a short section of the Peace River to allow for construction of the dam across the main channel of the river, and they are required in advance of river diversion that is scheduled for September 2020. As of March 31, 2020, the concrete lining of both diversion tunnels was nearly complete.

  We also completed the roller-compacted concrete placements for the Site C spillways buttress in October 2019, seven months ahead of schedule.

  Work advanced in areas away from the dam site, including along the transmission line, in the future reservoir area and along Highway 29.

- **Project workforce:** During March 2020, there were 4,896 people working on the Site C project, including 3,454 workers from B.C. (71 per cent of the total workforce), 353

Indigenous workers, 461 women and 751 workers from the Peace River Regional District. The March 2020 employment figures were a project record, and 26 workers more than the previous project record in August 2019, which was 4,870 workers.

- **Community benefits:** In December 2019, BC Hydro announced its first grant recipients for the BC Hydro Peace Agricultural Compensation Fund, providing funds for Peace Region agricultural projects. We also distributed funds to 17 Peace Region non-profit organizations through our Generate Opportunities (GO) Fund. Since 2016, more than half of the $800,000 GO Fund has been distributed to 49 projects that support community-enriching services in the Peace Region.

  Also this year, BC Hydro and Northern Lights College provided Indigenous students with the necessary skills to pursue carpentry employment opportunities through a pre-carpentry skills pilot program at Site C. This program was successfully delivered in April 2019 and it is planned to be delivered again in 2020/21. Seven Indigenous students from this program were hired by contractors on the project, with one student entering an apprentice program to become a journeyperson carpenter.

  In November 2019, BC Hydro – along with BC Housing and the City of Fort St. John – announced the official completion of 50 new affordable housing units in Fort St. John. Up to 40 units are available for rent to BC Hydro employees and their families during construction of the Site C project, and at the completion of construction, all 50 units will be provided as affordable housing for low and moderate-income households.

- **Safety:** Site C remains a complex, multi-discipline worksite, multi-employer project with significant safety hazards both on-site and off-site. Over the past year, BC Hydro has taken many steps to increase the focus on working safely and improving safety performance at the site. Many of these were brought forward by the Joint Safety Steering Committee with BC Hydro and major Site C contractors. We also developed a new set of performance indicators for safety and regulatory compliance at Site C.

  On March 18, 2020, in response to the increasing escalation of the COVID-19 pandemic and Public Health Officer guidance, BC Hydro began to scale back activities at the site and focus only on critical milestones, such as work to achieve river diversion in fall 2020.

  This decision allowed BC Hydro to de-densify the work site and on-site worker accommodations. Other essential work, such as keeping the site secure and meeting the project's environmental and regulatory commitments, continued as planned.

  Work also continued in areas off-site, including the realignment of Highway 29, the transmission line construction and clearing activities. The majority of workers in these areas did not stay in camp and can more easily practice physical distancing on their work sites.

  Following this decision to scale back work at the site, the number of people staying in the worker accommodation was reduced by approximately 50 per cent.

- **Project oversight:** To ensure the Site C project is developed on time and on budget, an independent expert Project Assurance Board advises the Site C Project Board. Established in January 2018, the Project Assurance Board provides enhanced oversight to future 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.

  There were 17 Project Assurance Board meetings held in 2019/20. In addition, BC Hydro retained EY Canada to provide an independent project assurance function and assist with identifying project risks and implementing effective mitigation strategies.

Goal 4: Help Make Renewable, Clean Power British Columbia's Leading Energy Source

Objective 4.1: BC Hydro will strengthen its legacy of renewable, clean power and conservation investments through its energy-efficiency and conservation programs, capacity reduction initiatives and support of low-carbon electrification.

Key Highlights

- The energy savings from energy efficiency and conservation initiatives of 735 gigawatt-hours per year (GWh/year) was 5 per cent higher than the target of 700 GWh/year due to higher than planned savings across the portfolio, with the biggest contribution to the variance occurring with codes and standards savings.
- We continued to exceed our Clean Energy performance measure target of 93 percent, with a result of 96.3 per cent of electricity in the province generated from clean or renewable resources.
- The BCUC approved two new rates, developed by BC Hydro in consultation with fleet vehicle customers, to facilitate electrification of vehicle and vessel fleets, and help to reduce greenhouse-gas emissions in B.C.

Performance Measure(s)[1]	2018/19 Actuals	2019/20 Target	2019/20 Actuals	2020/21 Target	2021/22 Target
4.a Energy Conservation Portfolio (New incremental GWh/year)[2]	868	700	735	700	500
4.b Clean Energy (%)	97.8	93.0	96.3	93.0	93.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.

[2] Annual targets are part of a longer-term Demand Side Management Plan that is set to fulfill the *Clean Energy Act* requirement to meet at least two-thirds of future demand growth by 2020 and BC Hydro's long-term planning needs.

Discussion of Results

We continued to exceed our Clean Energy performance measure target. This measure represents the objective in the *Clean Energy Act* that at least 93 per cent of electricity generation in the province is from clean or renewable resources.

BC Hydro continued to have strong performance from our energy efficiency and conservation initiatives and exceeded the Energy Conservation Portfolio target of 700 GWh/yr. Offers and programs to support low income and residential customers, as well as customers in the non-integrated areas gained traction in the market in 2019/20 and improved affordability for participating customers by helping them be more energy efficient and reducing their energy bills. We also continued to advance discussions to identify opportunities for diesel reduction and local renewable opportunities with several non-integrated communities.

In August 2019, B.C. and Canada signed a Memorandum of Understanding on electrification of the natural gas and liquefied natural gas industry in B.C. and agreed to pursue funding for three projects: the North Montney Power Supply project, the Bear Mountain-Dawson Creek Voltage Conversion Project and the CleanBC Facilities Electrification Fund.

In March 2020, the BCUC approved BC Hydro's application for two new rates to facilitate electrification of fleet vehicles and vessels. These new rates were developed by BC Hydro in consultation with fleet vehicle customers and will remove a barrier to electrification of vehicle and vessel fleets, while helping to reduce greenhouse-gas emissions in B.C.

BC Hydro will develop a new measure to support and align with the government's CleanBC plan in 2020/21, following the release of the Phase 2 of the Comprehensive Review final report.

Financial Report

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, 2020 and should be read in conjunction with the 2019/20 Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2020 and 2019.

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, 2020 was $705 million, $1.13 billion higher than the prior fiscal year. The increase in net income after regulatory account transfers was primarily driven by the elimination of the Rate Smoothing Regulatory Account, which resulted in a write-off of $1.04 billion in the prior fiscal year.

- The COVID-19 pandemic did not have a significant impact on BC Hydro's financial results for the year ended March 31, 2020.

- Domestic revenues for the year ended March 31, 2020 were $5.39 billion, a decrease of $39 million (or 1 per cent) compared to the prior fiscal year. This decrease was mainly driven by lower surplus sales, due to low water inflows and low reservoir storage levels. Large industrial revenues were also lower, mainly in the pulp and paper and wood sectors caused by curtailments driven by fibre supply shortages and a weak lumber market. This decrease was partially offset by higher average customer rates that reflect the 1.76 per cent interim net bill increase as approved by the British Columbia Utilities Commission (BCUC) effective April 1, 2019.

- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2020 were $3.08 billion, a $744 million decrease over the prior fiscal year. The decrease in capital expenditures for the year ended March 31, 2020 was primarily due to the completion of the purchase of the remaining two-thirds interest in the Waneta Dam in the prior fiscal year (July 26, 2018). BC Hydro continues to invest significantly in capital projects/programs to upgrade its existing assets and build new infrastructure, including the Site C, Peace Region Electricity Supply, Transmission Wood Structure and Framing Replacement, Distribution Wood Poles Replacements, LNG Canada Load Interconnection, Supply Chain Applications and UBC Load Increase Stage 2 projects.

Consolidated Results of Operations

for the years ended March 31 ($ in millions)		**2020**		2019		Change
Total Revenues	**$**	**6,269**	$	6,576	$	(307)
Net Income (Loss)	**$**	**705**	$	(428)	$	1,133
Capital Expenditures	**$**	**3,082**	$	3,826	$	(744)
Payment to the Province	**$**	**-**	$	59	$	(59)
GWh Sold (Domestic)		**52,113**		54,643		(2,530)

as at March 31 ($ in millions)		**2020**		2019		Change
Total Assets and Regulatory Balances	**$**	**39,068**	$	36,567	$	2,501
Shareholder's Equity	**$**	**5,654**	$	4,946	$	708
Retained Earnings	**$**	**5,638**	$	4,933	$	705
Debt to Equity		**81 : 19**		82 : 18		n/a
Number of Domestic Customer Accounts		**2,082,226**		2,049,157		33,069

Revenues

For the year ended March 31, 2020, total revenues of $6.27 billion, were $307 million lower than the prior fiscal year. The decrease was due to lower trade revenues of $268 million and lower domestic revenues of $39 million.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [1]	
for the years ended March 31	**2020**	2019	**2020**	2019	**2020**	2019
Domestic Revenues						
Residential	**$ 2,169**	$ 2,127	**17,993**	18,000	**$ 120.55**	$ 118.17
Light industrial and commercial	**1,942**	1,925	**18,692**	19,007	**103.89**	101.28
Large industrial	**850**	873	**13,398**	13,896	**63.44**	62.82
Surplus Sales	**1**	115	**182**	2,230	**5.49**	51.57
Other sales	**431**	392	**1,848**	1,510	**-**	-
Total Domestic Revenues	**$ 5,393**	$ 5,432	**52,113**	54,643	**$ 103.49**	$ 99.41
Trade Revenues						
Gross electricity and gas	**$ 1,309**	$ 1,755	**29,573**	28,158	**$ 39.80**	$ 53.62
Less: forward electricity and gas purchases	**(433)**	(611)	**-**	-	**-**	-
Total Trade Revenues	**$ 876**	$ 1,144	**29,573**	28,158	**$ 29.62**	$ 40.63
Total Revenues	**$ 6,269**	$ 6,576	**81,686**	82,801	**$ 76.75**	$ 79.42

[1]The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.

Domestic Revenues

For the year ended March 31, 2020, domestic revenues were $5.39 billion, a decrease of $39 million (or 1 per cent) compared to the prior fiscal year. This decrease was mainly driven by lower surplus sales, due to low water inflows and low reservoir storage levels. Large industrial revenues were also lower, mainly in the pulp and paper and wood sectors caused by curtailments driven by fibre supply shortages and a weak lumber market. This decrease was partially offset by higher average customer rates that reflect the 1.76 per cent interim net bill increase as approved by the BCUC effective April 1, 2019. In addition, other sales were higher, primarily due to higher revenue related to the purchase of two-thirds of the interest in the Waneta Dam and Generating Facility that took place in July 2018.

Trade Revenues

Powerex Corp. (Powerex), a wholly owned subsidiary of the Company, 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.

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities earn income to lower the Company's customer rates and to help balance its system by being able to import energy to meet domestic demand when there is a supply shortage and export energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements are met.

Total trade revenues for the year ended March 31, 2020 were $876 million, a decrease of $268 million (or 23 per cent) compared with the prior fiscal year. The decrease in trade revenues was primarily driven by lower average energy sales prices.

Operating Expenses

For the year ended March 31, 2020, total operating expenses of $4.98 billion were $296 million (or 6 per cent) higher than the prior fiscal year. The increase over the prior fiscal year was primarily due to higher energy costs of $189 million, higher other costs (net of recoveries) of $62 million, higher personnel costs of $55 million, and higher amortization and depreciation expense of $39 million. This was partially offset by lower materials and external services of $35 million.

Energy Costs

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and 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.

Total energy costs for the year ended March 31, 2020 were $2.37 billion, $189 million (or 9 per cent) higher than the prior fiscal year. The increase was primarily due to higher domestic energy costs of $185 million, and higher trade energy costs of $4 million.

for the years ended March 31	(in millions) 2020	(in millions) 2019	(gigawatt hours) 2020	(gigawatt hours) 2019	($ per MWh)[2] 2020	($ per MWh)[2] 2019
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 293**	$ 331	**39,801**	42,187	**$ 7.36**	$ 7.85
Purchases from Independent Power Producers	**1,314**	1,231	**14,475**	14,248	**90.78**	86.40
Other electricity purchases - Domestic	**133**	125	**3,471**	2,036	**38.32**	61.39
Gas and transportation for thermal generation	**7**	13	**172**	190	**40.70**	68.42
Transmission charges and other expenses	**(8)**	14	**106**	103	**-**	-
Non-Treaty storage and co-ordination agreements	**38**	(182)	**-**	-	**-**	-
Allocation from (to) trade energy	**(35)**	25	**(940)**	650	**37.20**	52.83
Total Domestic Energy Costs	**$ 1,742**	$ 1,557	**57,085**	59,414	**$ 30.52**	$ 26.21
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 713**	$ 967	**28,642**	29,475	**$ 24.89**	$ 33.18
Less: forward electricity and gas purchases	**(433)**	(611)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**280**	356	**-**	-	**-**	-
Transmission charges and other expenses	**313**	293	**-**	-	**-**	-
Allocation (to) from domestic energy	**35**	(25)	**940**	(650)	**37.20**	52.83
Total Trade Energy Costs	**$ 628**	$ 624	**29,582**	28,825	**$ 21.23**	$ 21.65
Total Energy Costs	**$ 2,370**	$ 2,181	**86,667**	88,239	**$ 27.35**	$ 24.72

[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 $ per MWh represents the gross unit cost per physical electricity and gas transaction. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.

Domestic Energy Costs

Domestic energy costs for the year ended March 31, 2020 were $1.74 billion, $185 million (or 12 per cent) higher than the prior fiscal year. The increase in costs was primarily due to higher Non-Treaty Storage and Co-ordination agreement costs due to higher net water storage in the current year, and higher costs from Independent Power Producers (IPP) due to higher deliveries from wind IPPs, an increased number of IPPs in operation and fewer plant outages. The higher costs were partially offset by lower water rental payments. Water rental payments are based on the prior calendar year's hydro generation volumes and were driven by lower water inflows and dry weather in the prior calendar year.

Trade Energy Costs

Total trade energy costs for the year ended March 31, 2020 were $628 million, an increase of $4 million (or 1 per cent) compared with the prior fiscal year. The increase in trade energy costs was primarily driven by higher average energy purchase volumes for the period.

Water Inflows and Reservoir Storage

Water inflows to the system for the year ended March 31, 2020 were below average but higher than the prior fiscal year. The below average water inflows during the year ended March 31, 2020 were primarily due to below average inflows to the Kootenay plants, small hydro projects, and the Williston Reservoir (Peace River basin). For the Kinbasket Reservoir (Columbia River basin), inflows were near average.

System energy storage continues to track below the historic average due to low inflows from the first two quarters of the fiscal year. However, system energy storage at March 31, 2020 was higher than at March 31, 2019.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2020 were $685 million, $55 million (or 9 per cent) higher than the prior fiscal year primarily due to higher employee benefits costs as a result of increased current service pension costs and the BC employer health tax.

Materials and External Services

Expenditures on materials and external services for the year ended March 31, 2020 were $613 million, $35 million (or 5 per cent) lower than the prior fiscal year primarily due to lower storm restoration activities and lower Demand-Side Management program costs.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, and amortization of intangible assets. For the year ended March 31, 2020, amortization and depreciation expense was $988 million, $39 million (or 4 per cent) higher than the prior fiscal year primarily due to additional property, plant and equipment placed in service.

Grants and Taxes

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

Total grants and taxes for the year ended March 31, 2020 were $254 million, $12 million (or 5 per cent) lower than the prior fiscal year primarily due to lower taxes incurred by Powerex relating to trading activity in the United States.

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, 2020, other costs net of recoveries were $146 million, $62 million (or 74 per cent) higher than the prior fiscal year. The increase was primarily due to a higher environmental provision related to the remediation of polychlorinated biphenyl (PCB) and asbestos, and higher dismantling costs related to the decommissioning of assets.

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, 2020 were $72 million, comparable to $70 million in the prior fiscal year.

Finance Charges

Finance charges for the year ended March 31, 2020 were $1.65 billion, $449 million (or 38 per cent) higher than the prior fiscal year. The increase was primarily due to unrealized losses on future debt hedges used to economically hedge the interest rates on future debt issuances, and higher volume of long-term debt and short-term borrowings, partially offset by higher interest during construction costs which were capitalized. The unrealized losses on future debt hedges will be offset by lower interest costs when the future debt is issued.

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 (Loss).

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, including to better match costs and benefits for different generations of customers, and to defer 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)		**2020**		2019
Cost of Energy Variance Accounts				
Heritage Deferral Account	**$**	**(82)**	$	(95)
Non-Heritage Deferral Account		**99**		(168)
Trade Income Deferral Account		**(69)**		(324)
		(52)		(587)
Forecast Variance Accounts				
Total Finance Charges		**1**		53
Rate Smoothing (RSRA)		**-**		(815)
Non-Current Pension Costs		**(219)**		240
Debt Management		**778**		321
Storm Restoration Costs		**(8)**		19
Real Property Sales		**5**		10
Other		**(7)**		32
		550		(140)
Capital-Like Accounts				
Demand-Side Management		**95**		111
Site C		**(2)**		-
IFRS Property, Plant & Equipment		**45**		67
		138		178
Non-Cash Accounts				
Environmental Provisions & Costs		**56**		(1)
First Nations Provisions & Costs		**21**		22
Other		**(5)**		(5)
		72		16
Amortization of regulatory accounts		**23**		(442)
Interest on regulatory accounts		**17**		28
Net change in regulatory accounts	**$**	**748**	$	(947)

The Company adopted IFRS 16, *Leases* on April 1, 2019, which resulted in an increase of $64 million to the opening net regulatory asset balance as at April 1, 2018 (the $64 million is not included in the above table). Refer to Note 27 in the Audited Consolidated Financial Statements for more detail on the impact of the adoption of IFRS 16.

For the year ended March 31, 2020, there was a net addition of $748 million to the Company's regulatory accounts compared to a net reduction of $947 million in the prior fiscal year. The net regulatory asset balance as at March 31, 2020 was $5.01 billion compared to $4.26 billion as at March 31, 2019.

Net additions to the regulatory accounts during the year ended March 31, 2020 included:

- $778 million of additions to the Debt Management Regulatory Account primarily due to decreases in the fair value of interest rate hedges resulting from a decrease in forward interest rates;
- $99 million of additions to the Non-Heritage Deferral Account primarily due to lower than planned domestic revenues; and
- $95 million of additions to the Demand-Side Management Regulatory Account, which support energy conservation.

These net additions were partially offset by:

- $219 million of reductions to the Non-Current Pension Costs Regulatory Account primarily due to an increase in the discount rate used to measure the pension liability;
- $82 million of reductions to the Heritage Deferral Account primarily due to lower than planned domestic cost of energy; and
- $69 million of reductions to the Trade Income Deferral Account due to higher than planned trade income.

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2020**	2019
Cost of Energy Variance Accounts		
Heritage Deferral Account	**$ (300)**	$ (485)
Non-Heritage Deferral Account	**205**	141
Trade Income Deferral Account	**(174)**	(261)
	(269)	(605)
Forecast Variance Accounts		
Total Finance Charges	**11**	20
Non-Current Pension Costs	**210**	486
Debt Management	**953**	163
Storm Restoration Costs	**21**	58
Real Property Sales	**56**	49
Other	**37**	77
	1,288	853
Capital-Like Accounts		
Demand-Side Management	**907**	915
Smart Metering & Infrastructure	**195**	217
IFRS Property, Plant & Equipment	**1,079**	1,064
Site C	**508**	491
Capital Project Investigation Costs	**5**	10
	2,694	2,697
Non-Cash Accounts		
Environmental Provisions & Costs	**260**	227
First Nations Provisions & Costs	**495**	505
IFRS Pension	**459**	497
Other	**78**	83
	1,292	1,312
Net Regulatory Asset	**$ 5,005**	$ 4,257

BC Hydro has or has applied for regulatory mechanisms to collect 23 of 25 regulatory accounts in use or with balances at March 31, 2020 in rates over various periods, which represent approximately 90 per cent of the net regulatory asset balance.

Comparison with Service Plan

The *Budget Transparency and Accountability Act* requires that BC Hydro file a service plan each year. BC Hydro's 2019/20-2021/22 Service Plan (Service Plan) was filed in February 2019 with forecast net income for 2019/20 of $712 million.

The table below provides an overview of BC Hydro's 2019/20 financial results, relative to its Service Plan.

(in millions)	Actual	Service Plan[2]	Variance to Service Plan[2]
For the year ended March 31,	**2020**	**2020**	
Revenues			
Domestic	$ 5,393	$ 5,654	$ (261)
Trade	876	651	225
	6,269	6,304	(36)
Expenses			
Operating Costs			
Cost of energy	2,370	2,367	(3)
Other operating expenses			
Personnel expenses, materials and external services [1]	1,196	1,204	8
Amortization	988	925	(63)
Finance charges	1,645	756	(889)
Grants and taxes	254	258	4
Other	176	108	(68)
	6,629	5,619	(1,011)
Net Income Before Movement in Regulatory Balances	(360)	685	(1,046)
Net Movement in Regulatory Balances	1,065	27	1,038
Net Income	$ 705	$ 712	$ (7)

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

[2] Column may not add due to rounding.

Net income for 2019/20 was $705 million, compared to forecast net income of $712 million in the Service Plan filed in February 2019. The lower net income was mainly the result of higher capital project write-offs and a provision for potential non-compliance penalties under the Mandatory Reliability Standards.

Dividend Payment to the Province

In accordance with Order in Council No. 095/2014 from the Province, for 2017/18 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 reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

The 2018/19 payment to the Province was $59 million and was paid in June 2019.

As at March 31, 2020, the Company's net debt to equity ratio was 81:19 and the payment for 2019/20 was $nil.

Liquidity and Capital Resources

Cash flow provided by operating activities for the year ended March 31, 2020 was $1.78 billion, compared with $1.94 billion in the prior fiscal year. The decrease was mainly due to lower trade income and higher domestic cost of energy.

The long-term debt balance net of sinking funds as at March 31, 2020 was $23.47 billion compared to $22.18 billion as at March 31, 2019. The increase was mainly a result of an increase in net long-term bond issuances (net of redemptions) to fund BC Hydro's capital expenditures. This was partially offset by lower revolving borrowings.

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)		**2020**		2019
Transmission lines and substations replacements and expansion	**$**	**375**	$	431
Generation replacements and expansion		**306**		372
Distribution system improvements and expansion		**514**		504
General, including technology, vehicles and buildings		**268**		183
Waneta 2/3 interest acquisition		**-**		1,219
Site C		**1,619**		1,117
Total Capital Expenditures[1]	**$**	**3,082**	$	3,826

[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 decrease in capital expenditures of $744 million for the year ended March 31, 2020 compared to the prior fiscal year was primarily due to the completion of the purchase of the remaining two-thirds interest in the Waneta Dam in the prior year (July 26, 2018). This was partially offset by higher Site C capital expenditures.

Transmission lines and substation capital expenditures include expenditures on the following projects/programs: Peace Region Electricity Supply, Transmission Wood Structure and Framing Replacement, LNG Canada Load Interconnection, UBC Load Increase Stage 2, Fort St. John and Taylor Electric Supply, and Barnard Substation Feeder Section Replacement.

Generation capital expenditures include expenditures on the following projects: Mica Units 1 to 4 Generator Transformers Replacement, Bridge River 2 Units 7 and 8 Upgrade, John Hart Generating Station Replacement, W.A.C. Bennett Dam Spillway Gate Upgrade, G.M. Shrum Generator Control Systems Upgrade, Mica Modernize Controls, Ruskin Dam Safety and Powerhouse Upgrade, Wahleach Refurbish Generator, and John Hart Dam Seismic Upgrade.

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

General capital expenditures include expenditures on the Supply Chain Applications project, Microsoft Enterprise Agreement, vehicles, various building development programs, and other technology projects.

Site C Project expenditures relate to site preparation, reservoir clearing, transmission lines and substation, engineering and design, highway realignment, main civil works, generating station and spillway, as well as social and land programs.

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.

BC Hydro's Fiscal 2020-2021 Revenue Requirements Application

In February 2019, BC Hydro filed an Application with the BCUC to approve its revenue requirements for a two-year test period covering 2019/20 and 2020/21. In August 2019, BC Hydro provided an Evidentiary Update to its Application, requesting a net rate increase of 1.76 per cent for 2019/20 and a net rate decrease of 1.01 per cent for 2020/21. In March 2020, the BCUC concluded an Oral Hearing, and a final decision is expected by September 2020.

COVID-19 Customer Relief Program

On April 7, 2020, the BCUC approved BC Hydro's application to provide up to three months (April through June) of bill relief for customers impacted by COVID-19. Under the bill relief program, residential customers who are unable to work as a result of COVID-19 can apply for bill credits based on their average monthly consumption. Certain commercial customers who have closed their businesses as a result of COVID-19 can have payments waived. Industrial customers can defer payment of 50% of their monthly bills. The credited and waived amounts, and any impaired deferred payment amounts, will be recorded in regulatory accounts for future recovery.

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 2020-2021 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 five factors:

- Hydro generation;
- Customer load;
- Electricity/gas trade margins;
- Deliveries from electricity purchase agreement contracts; and
- Interest rates.

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 customer load, 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 doing so, BC Hydro attempts to optimize the combined effects of these elements and reduce the net energy cost for our customers.

The impacts of COVID-19 are expected to impact these elements in the future. In particular, customer load is expected to be impacted across all customer segments. The impacts will depend on the speed and nature of both the near-term economic downtown caused by COVID-19, and the mid-to-long-term recovery and lasting effects.

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) and enabling our ability to take advantage of short-term market price variations. The amount of available generation is driven primarily by hydrology - the amount and timing of inflows into BC Hydro-dispatched plants and reservoirs. The range of inflows, year to year, can significantly influence available generation: over 15,000 GWh (or approximately 25 per cent of current domestic demand) separates the wettest years from the driest in the most recent 48 years in BC Hydro's records. The amount of available generation 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.

Customer Load

Customer load 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 entails 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. In addition, there can be variability for residential and commercial customers due to general economic conditions and the rate of uptake in demand-side management programs.

The COVID-19 pandemic has resulted in reduced electricity demand relative to normal levels beginning from about mid-March through the remainder of fiscal 2020. The reduction in electricity demand is expected to continue into the next fiscal year, although the extent to which electricity consumption will continue to be affected is uncertain at this time.

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. Weather can have a significant impact on residential load with colder years resulting in higher demand for electrical heating than in average or warm years.

Electricity/Gas Trade Margins

Electricity and gas trade margins are impacted by electricity and gas prices which are variable and impacted by gas and electricity market fundamentals.

Deliveries from Electricity Purchase Agreement Contracts

Energy delivered under electricity purchase agreement contracts 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 electricity purchase agreement contracts changes, BC Hydro's average energy cost changes. BC Hydro's portfolio of electricity purchase agreement contracts 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, 2020, overall energy delivered from Independent Power Projects was higher than forecast. In particular, hydro and wind projects delivered more energy than expected. Higher than forecast deliveries from these projects was partially offset by lower than forecast deliveries from biomass and thermal generation projects.

Interest Rates

A portion of BC Hydro's existing debt will be impacted by the 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 debt management purposes within limits established by its liability risk management strategic plan.

As at March 31, 2020, approximately 16 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 long-term interest rates, as at March 31, 2020, BC Hydro had interest rate hedges in place with an aggregate notional principal of $5.0 billion, hedging a significant portion of its forecast long-term debt issuances out to and including 2024/25.

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 2020 forecast net income for 2020/21 at $712 million which is consistent with the amount required by Order in Council No. 051.

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 2020/21 assumes average water inflows (100 per cent of average), domestic sales of 53,656 GWh, average market energy prices of US $27.67/MWh, short-term interest rates of 1.47 per cent, and a Canadian to US dollar exchange rate of US $0.7616.

The COVID-19 pandemic continues to adversely impact global activity and has contributed to significant volatility and negative pressure in financial markets. The impact of COVID-19 has been rapidly evolving, and as cases of the virus have continued to be identified, many countries including Canada have reacted by instituting public health measures, including quarantines and restrictions on travel. On March 26, 2020 the Province declared a state of emergency. The outbreak could have a sustained adverse impact on economic and market conditions and could adversely impact BC Hydro's future performance by causing a decrease in customer load, volatility in electricity/gas trade margins and interest rates, difficulty accessing debt and project delays.

While BC Hydro engages in emergency preparedness, including business continuity planning, to mitigate risks, the rapid development and fluidity of this situation limits the ability to predict the ultimate adverse impact of COVID-19 on BC Hydro. Any of the aforementioned events in isolation or in combination, could have a material negative impact on BC Hydro's performance, financial condition, results of operations and cash flows.

Earnings Sensitivity

The following table shows the estimated effect on earnings of changes in some key variables, before regulatory account transfers. The analysis is based on business conditions and generation volumes forecast for 2020/21. 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 earnings before regulatory account transfers (in millions)	5 year high	5 year low	2019/20
Customer Load [1]	+/-1%	$35	52,413 GWh	51,023 GWh	51,931 GWh
Interest rates [2]	+/- 100 basis points	$30	2.01% [2]	0.87% [2]	1.94% [2]
Electricity/Gas trade margins [3]	+/-10%	$25	$520	$127	$248
Hydro generation [4]	+/-1%	$10	49,352 GWh	40,383 GWh	40,383 GWh
Exchange rates (US/ CDN)	+/- $0.01	$5	$0.78 [5]	$0.75 [5]	$0.75[5]

[1] Assumes a percentage change is applied equally to all customer classes. Assumes a change in customer load is offset by a corresponding change in market electricity purchases or surplus sales.

[2] Relates to debt subject to interest rate variability. Interest rates are the annual daily average Canadian short-term interest rates (3-month Canadian Dollar Offered Rate).

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

[4] Assumes a change in hydro generation is offset by a corresponding change in market electricity purchases or surplus sales.

[5] Exchange rates for 2019/20 are the Bank of Canada average daily rates. Prior to 2017/18, exchange rates were the annual daily average US Dollar noon rates.

Management Report

The consolidated financial statements of British Columbia Hydro and Power Authority (BC Hydro) are the responsibility of management and have been prepared in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily involves the use of estimates which have been made using careful judgment. In management's opinion, the consolidated financial statements have been properly prepared within the framework of the accounting policies summarized in the consolidated financial statements and incorporate, within reasonable limits of materiality, all information available at June 4, 2020. The consolidated financial statements have also been reviewed by the Audit & Finance Committee and approved by the Board of Directors. Financial information presented elsewhere in this Annual Service Plan Report is consistent with that in the consolidated financial statements.

Management maintains systems of internal controls designed to provide reasonable assurance that assets are safeguarded and that reliable financial information is available on a timely basis. These systems include formal written policies and procedures, careful selection and training of qualified personnel 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 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, comprehensive income 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 Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit & Finance Committee, comprised of directors who are not employees, meets regularly with the external auditors, the internal auditors and management to satisfy itself that each group has properly discharged its responsibility 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 Committee, with and without the presence of management.

Chris O'Riley
President and Chief Executive Officer

David Wong
Executive Vice President, Finance, Technology, Supply Chain and Chief Financial Officer

Vancouver, Canada
June 4, 2020

OFFICE OF THE
Auditor General
of British Columbia

623 Fort Street
Victoria, British Columbia
Canada V8W 1G1
P: 250.419.6100
F: 250.387.1230
www.bcauditor.com

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 Petroleum Resources, 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, 2020, and the consolidated statements of comprehensive income (loss), 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, 2020, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

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 Matter

The consolidated financial statements of the British Columbia Hydro and Power Authority for the year ended March 31, 2019, were audited by another auditor who expressed an unmodified opinion on those statements on June 12, 2019.

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.

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.

Prior to the date of my auditor's report, I obtained the draft 2019/20 Annual Service Plan Report. If, based on the work I have performed on this other information, I conclude that there is a material misstatement therein, I am required to report that fact in this auditor's report. I have nothing to report in this regard.

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 (IFRS), 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 Financial Statements

My objectives are to obtain reasonable assurance about whether the group's 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.

Russ Jones

Russ Jones, FCPA, FCA, ICD.D
Auditor General (Acting)

Victoria, British Columbia, Canada
June 4, 2020

OFFICE OF THE
Auditor General
of British Columbia

Audited Financial Statements

Consolidated Statements of Comprehensive Income (Loss)

for the years ended March 31 (CAD$ in millions)		**2020**		2019 (Note 27)
Revenues (Note 4)				
Domestic	**$**	**5,393**	$	5,432
Trade		**876**		1,144
		6,269		6,576
Expenses				
Operating expenses (Note 5)		**4,984**		4,688
Finance charges (Note 6)		**1,645**		1,196
Net Income (Loss) Before Movement in Regulatory Balances		**(360)**		692
Net movement in regulatory balances (Note 15)		**1,065**		(1,120)
Net Income (Loss)		**705**		**(428)**
OTHER COMPREHENSIVE INCOME (LOSS)				
Items That Will Be Reclassified to Net Income (Loss)				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 23)		**64**		(24)
Reclassification to income (loss) of derivatives designated as cash flow hedges (Note 23)		**(63)**		8
Foreign currency translation gains		**2**		3
Items That Will Not Be Reclassified to Net Income (Loss)				
Actuarial gain (loss)		**317**		(173)
Other Comprehensive Income (Loss) before movement in regulatory balances		**320**		**(186)**
Net movements in regulatory balances (Note 15)		**(317)**		173
Other Comprehensive Income (Loss)		**3**		(13)
Total Comprehensive Income (Loss)	**$**	**708**	$	(441)

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Financial Position

(CAD$ in millions)	**As at March 31 2020**	As at March 31 2019 (Note 27)	As at April 1 2018 (Note 27)
ASSETS			
Current Assets			
Cash and cash equivalents (Note 8)	**$ 115**	$ 84	$ 42
Restricted cash (Note 8)	**15**	109	77
Accounts receivable and accrued revenue (Note 9)	**770**	912	728
Inventories (Note 10)	**193**	168	144
Prepaid expenses	**140**	148	149
Current portion of derivative financial instrument assets (Note 23)	**106**	79	174
	1,339	1,500	1,314
Non-Current Assets			
Property, plant and equipment (Note 11)	**29,413**	27,334	24,439
Right-of-use assets (Note 12)	**1,405**	1,466	1,526
Intangible assets (Note 13)	**678**	602	591
Derivative financial instrument assets (Note 23)	**92**	49	156
Other non-current assets (Note 14)	**655**	609	629
	32,243	30,060	27,341
Total Assets	**33,582**	31,560	28,655
Regulatory Balances (Note 15)	**5,486**	5,007	5,955
Total Assets and Regulatory Balances	**$ 39,068**	$ 36,567	$ 34,610
LIABILITIES AND EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities (Note 16)	**$ 1,626**	$ 1,546	$ 1,665
Current portion of long-term debt (Note 17)	**3,843**	3,121	3,344
Current portion of unearned revenues and contributions in aid (Note 20)	**93**	87	85
Current portion of derivative financial instrument liabilities (Note 23)	**358**	89	114
	5,920	4,843	5,208
Non-Current Liabilities			
Long-term debt (Note 17)	**19,843**	19,261	17,020
Lease liabilities (Note 19)	**1,425**	1,470	1,519
Derivative financial instrument liabilities (Note 23)	**708**	294	65
Unearned revenues and contributions in aid (Note 20)	**2,095**	1,905	1,758
Post-employment benefits (Note 22)	**1,560**	1,752	1,474
Other non-current liabilities (Note 24)	**1,382**	1,346	1,369
	27,013	26,028	23,205
Total Liabilities	**32,933**	30,871	28,413
Regulatory Balances (Note 15)	**481**	750	751
Total Liabilities and Regulatory Balances	**33,414**	31,621	29,164
Shareholder's Equity			
Contributed surplus	**60**	60	60
Retained earnings	**5,638**	4,933	5,420
Accumulated other comprehensive loss	**(44)**	(47)	(34)
	5,654	4,946	5,446
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$ 39,068**	$ 36,567	$ 34,610

Commitments and Contingencies (Notes 11 and 25), and Subsequent Events (Note 28)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

Ken Peterson
Board Chair

Len Boggio, FCPA, FCA, ICD.D
Chair, Audit & Finance Committee

Consolidated Statements of Changes in Equity

(CAD$ in millions)	Cumulative Translation Reserve	Unrealized Income (Loss) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)	Contributed Surplus	Retained Earnings (Note 27)	Total
Balance as at April 1, 2018	$ (5)	$ (29)	$ (34)	$ 60	$ 5,420	$ 5,446
Payment to the Province (Note 21)	-	-	-	-	(59)	(59)
Comprehensive Income (Loss)	3	(16)	(13)	-	(428)	(441)
Balance as at March 31, 2019	(2)	(45)	(47)	60	4,933	4,946
Comprehensive Income	2	1	3	-	705	708
Balance as at March 31, 2020	$ -	$ (44)	$ (44)	$ 60	$ 5,638	$ 5,654

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

for the years ended March 31 (CAD$ in millions)	**2020**	2019 (Note 27)
Operating Activities		
Net income (Loss)	**$ 705**	$ (428)
Regulatory account transfers (Note 15)	**(748)**	947
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 7)	**988**	949
Unrealized losses on derivative financial instruments	**728**	286
Post-employment benefits expense	**131**	106
Interest accrual	**872**	854
Other items	**102**	45
	2,778	2,759
Changes in working capital and other assets and liabilities (Note 18)	**(50)**	96
Interest paid	**(945)**	(920)
Cash provided by operating activities	**1,783**	1,935
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(2,782)**	(3,766)
Cash used in investing activities	**(2,782)**	(3,766)
Financing Activities		
Long-term debt issued (Note 17)	**1,608**	2,418
Long-term debt retired (Note 17)	**(175)**	(1,287)
Receipt of revolving borrowings	**10,484**	8,865
Repayment of revolving borrowings	**(10,680)**	(7,981)
Payment to the Province (Note 21)	**(59)**	(159)
Payment of principal portion of lease liability	**(77)**	(75)
Other items	**(71)**	92
Cash provided by financing activities	**1,030**	1,873
Increase in cash and cash equivalents	**31**	42
Cash and cash equivalents, beginning of year	**84**	42
Cash and cash equivalents, end of year	**$ 115**	$ 84

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), Powertech Labs Inc. (Powertech), and Columbia Hydro Constructors Ltd. (Columbia), (collectively with BC Hydro, the Company). All intercompany transactions and balances are eliminated on consolidation. On July 26, 2018, the Company completed the purchase of the remaining two-thirds interest of Waneta Dam and Generating Facility (Waneta), see Note 11. Prior to this transaction, the Company accounted for its one-third interest in Waneta as a joint operation.

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. Effective April 1, 2019, the Company adopted IFRS 16, *Leases* (IFRS 16). The comparative figures for the prior year were restated on the adoption of IFRS 16. An explanation of how the transition to IFRS 16 has affected the reported financial position, financial performance and cash flows of the Company is provided in Note 27.

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 4, 2020.

(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(o).

(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) 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.

(vi) 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 balances are assessed to no longer be probable based on management's judgment, the balances are recorded in the Company's consolidated statements of comprehensive income (loss) 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 (loss) 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) Revenue

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 either under long-term contracts or are surplus to domestic load requirements. 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 hedging instrument losses that are recognized in the statement of comprehensive income. 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 hedging instrument gains that are recognized in the statement of comprehensive income (loss), 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 re-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 (loss).

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.

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 (loss) 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 – 65
Distribution	20 – 60
Buildings	5 – 60
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. Other intangible assets include California carbon allowances which are not amortized because they are used to settle obligations arising from carbon emissions regulations. 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. Natural gas 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 environmental product 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 and 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. For foreign currency exchange risk associated with electricity and natural gas commodity transactions, the related gains or losses are included in domestic revenues. 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 Revenue

Unearned revenue consists 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) 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.

(o) 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.

(p) 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 the claim will be settled 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 lawsuits. Further information regarding lawsuits in progress is disclosed in Note 25.

(q) 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 our 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 (loss) 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.

(r) 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.

(s) Jointly Controlled Operations

Prior to the purchase of the remaining 2/3 interest in Waneta Dam and Generating Facility on July 26, 2018, the Company had joint ownership and control over certain assets with third parties. A jointly controlled operation exists when there is a joint ownership and control of one or more assets to obtain benefits for the joint operators. The parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, related to the arrangement. Each joint operator takes a share of the output from the assets for its own exclusive use. These consolidated financial statements include the Company's share of the jointly controlled assets. The Company also records its share of any liabilities and expenses incurred jointly with third parties and any revenue from the sale or use of its share of the output in relation to the assets.

(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, 2020, and have not been applied in preparing these consolidated financial statements. In particular, the following new and amended standards become effective for the Company's annual periods beginning on or after the dates noted below:

- Amendments to IAS 1, *Presentation of Financial Statements (effective April 1, 2020)*
- Amendments to IFRS 3, *Business Combinations (effective April 1,2020)*
- Amendments to IAS 8, Accounting Policies, *Changes in Accounting Estimates and Errors* (effective April 1, 2020)
- Amendments to IFRS 7, *Financial Instruments: Disclosures (effective April 1, 2020)*
- Amendments to IFRS 9, *Financial Instruments (effective April 1, 2020)*
- Amendments to IAS 39, *Financial Instruments: Recognition and Measurement(effective April 1, 2020)*
- IFRS 17, *Insurance Contracts (effective April 1, 2021)*

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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

(CAD$ in millions)		**2020**		2019
Domestic				
Residential	**$**	**2,169**	$	2,127
Light industrial and commercial		**1,942**		1,925
Large industrial		**850**		873
Surplus sales		**1**		115
Other sales		**431**		392
Total Domestic		**5,393**		5,432
Total Trade[1]		**876**		1,144
Total Revenue	**$**	**6,269**	$	6,576

[1] Includes non-IFRS 15 revenues (2020 - $340M ; 2019 - $305M).

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, 2020 was $704 million (2019 - $867 million, April 1, 2018 - $741 million).

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

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

(CAD$ in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Unearned revenues	**$**	**296**	$	230	$	210
Contributions in aid (Note 20)		**1,892**		1,762		1,633
Customer deposits		**9**		13		15
	$	**2,197**	$	2,005	$	1,858

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

The following table reconciles the changes in the contract liabilities balances during the years ended March 31, 2020 and 2019:

(CAD$ in millions)		**Contract Liabilities**
Balance at April 1, 2018	**$**	**1,858**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(107)
Increases due to cash received, excluding amounts recognized as revenue during the period		230
Other[1]		24
Balance at March 31, 2019		**2,005**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(117)
Increases due to cash received, excluding amounts recognized as revenue during the period		280
Other[1]		29
Balance at March 31, 2020	**$**	**2,197**

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, 2020.

(CAD$ in millions)		**Less than 1 year**		**Between 1 and 5 years**		**More than 5 years**		**Total**
Energy sales	$	46	$	21	$	16	$	83
Contributions in aid		53		208		1,631		1,892
Skagit River Agreement		29		118		1,206		1,353
Other		57		86		44		187
	$	185	$	433	$	2,897	$	3,515

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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Note 5: Operating Expenses

(CAD$ in millions)	**2020**	2019
Electricity and gas purchases	**$ 1,880**	$ 1,645
Water rentals	**293**	331
Transmission charges	**197**	205
Personnel expenses	**685**	630
Materials and external services	**613**	648
Amortization and depreciation (Note 7)	**988**	949
Grants and taxes	**254**	266
Other costs, net of recoveries	**146**	84
Capitalized costs	**(72)**	(70)
	$ 4,984	$ 4,688

Note 6: Finance Charges

(CAD$ in millions)	**2020**	2019
Interest on long-term debt	**$ 872**	$ 854
Interest on lease liabilities	**51**	52
Interest on defined benefit plan obligations (Note 22)	**63**	56
Mark-to-market losses on derivative financial instruments (Note 23)	**774**	318
Other	**61**	46
Capitalized interest	**(176)**	(130)
	$ 1,645	$ 1,196

The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 3.8 per cent (2019 - 4.0 per cent).

Note 7: Amortization and Depreciation

(CAD$ in millions)	**2020**	2019
Depreciation of property, plant and equipment (Note 11)	**$ 814**	$ 774
Depreciation of right-of-use assets (Note 12)	**94**	92
Amortization of intangible assets (Note 13)	**80**	83
	$ 988	$ 949

Note 8: Cash and Cash Equivalents, and Restricted Cash

(CAD$ in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Cash	**$**	**37**	$	34	$	11
Short-term investments		**78**		50		31
	$	**115**	$	84	$	42

Restricted cash represents 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 only available to the Company upon liquidation of the investments or settlements of the trade obligations for which they have been pledged as security.

Note 9: Accounts Receivable and Accrued Revenue

(CAD$ in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Accounts receivable	**$**	**412**	$	640	$	492
Accrued revenue		**245**		192		170
Other		**113**		80		66
	$	**770**	$	912	$	728

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

Note 10: Inventories

(CAD$ in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Materials and supplies	**$**	**171**	$	161	$	142
Natural gas trading inventories		**22**		7		2
	$	**193**	$	168	$	144

There were no materials and supplies inventory impairments during the years ended March 31, 2020 and 2019. Natural gas inventory held in storage is 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 $46 million (2019 - $77 million).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Note 11: Property, Plant, and Equipment

(CAD$ in millions)	Generation	Transmission	Distribution	Land & Builidings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at April 1, 2018	$ 6,904	$ 6,959	$ 5,599	$ 697	$ 759	$ 4,274	$ 25,192
Net additions	2,397	516	442	30	105	241	3,731
Disposals and retirements	(10)	(10)	(31)	(1)	(10)	(17)	(79)
Balance at March 31, 2019	9,291	7,465	6,010	726	854	4,498	28,844
Net additions	390	188	461	45	86	1,786	2,956
Disposals and retirements	(10)	(11)	(32)	(1)	(23)	(15)	(92)
Balance at March 31, 2020	$ 9,671	$ 7,642	$ 6,439	$ 770	$ 917	$ 6,269	$ 31,708
Accumulated Depreciation							
Balance at April 1, 2018	$ (200)	$ (232)	$ (193)	$ (32)	$ (96)	$ -	$ (753)
Depreciation expense	(234)	(223)	(201)	(26)	(90)	-	(774)
Disposals and retirements	6	2	3	-	6	-	17
Balance at March 31, 2019	(428)	(453)	(391)	(58)	(180)	-	(1,510)
Depreciation expense	(263)	(229)	(207)	(27)	(88)	-	(814)
Disposals and retirements	3	4	5	1	16	-	29
Balance at March 31, 2020	$ (688)	$ (678)	$ (593)	$ (84)	$ (252)	$ -	$ (2,295)
Net carrying amounts							
At April 1, 2018	$ 6,704	$ 6,727	$ 5,406	$ 665	$ 663	$ 4,274	$ 24,439
At March 31, 2019	$ 8,863	$ 7,012	$ 5,619	$ 668	$ 674	$ 4,498	$ 27,334
At March 31, 2020	$ 8,983	$ 6,964	$ 5,846	$ 686	$ 665	$ 6,269	$ 29,413

(i) Prior to the purchase of the remaining two-thirds interest in Waneta on July 26, 2018, the Company included its one-third interest in Waneta with a net book value of $668 million (April 1, 2018 - $674 million) in Generation assets.

On August 1, 2017, BC Hydro agreed to exercise its option to purchase the remaining two-thirds interest of Waneta from Teck Resources (Teck) for $1.20 billion. Following receipt of BCUC approval in July 2018, BC Hydro completed the transaction on July 26, 2018. The transaction has been accounted for as an asset acquisition, with the purchase price being allocated to the applicable integrated components of the property, plant and equipment acquired.

Depreciation expense on the Waneta assets for the year ended March 31, 2020 was $59 million (2019 - $46 million).

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1.16 billion (2019 - $1.11 billion, April 1, 2018 - $1.05 billion) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2020 was $30 million (2019 - $29 million).

(iii) The Company received government grants arising from the Columbia River Treaty related to three dams built by the Company in the mid-1960s to regulate the flow of the Columbia River. The grants were made to assist in financing the construction of the dams. The grants were deducted from the carrying amount of the related dams. In addition, the Company received, in the current year and prior years, government grants for the construction of transmission lines and has deducted the grants received from the cost of the asset. BC Hydro received government grants of $23 million during the year ended March 31, 2020 (2019 - $nil).

(iv) The Company has contractual commitments to spend $2.87 billion on major property, plant and equipment projects (on individual projects greater than $50 million) as at March 31, 2020.

(v) During the year ended March 31, 2020, the Company recorded losses of $62 million (2019 - $61 million) from asset retirement and asset/project write-offs.

Note 12: Right-of-Use Assets

(CAD$ in millions)	**Long-term energy purchase agreements**	**Property**	**Equipment/ Other**	**Total**
Cost				
Balance at April 1, 2018	$ 1,940	$ 37	$ -	$ 1,977
Net additions	12	17	3	32
Balance at March 31, 2019	1,952	54	3	2,009
Net additions	26	7	-	33
Balance at March 31, 2020	$ 1,978	$ 61	$ 3	$ 2,042
Accumulated Depreciation				
Balance at April 1, 2018	$ (436)	$ (15)	$ -	$ (451)
Depreciation expense	(88)	(3)	(1)	(92)
Balance at March 31, 2019	(524)	(18)	(1)	(543)
Depreciation expense	(89)	(4)	(1)	(94)
Balance at March 31, 2020	$ (613)	$ (22)	$ (2)	$ (637)
Net carrying amounts				
At April 1, 2018	$ 1,504	$ 22	$ -	$ 1,526
At March 31, 2019	$ 1,428	$ 36	$ 2	$ 1,466
At March 31, 2020	$ 1,365	$ 39	$ 1	$ 1,405

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Note 13: Intangible Assets

(CAD$ in millions)	**Land Rights**	**Internally Developed Software**	**Purchased Software**	**Other**	**Work in Progress**	**Total**
Cost						
Balance at April 1, 2018	$ 247	$ 109	$ 263	$ 33	$ 36	$ 688
Net additions	29	6	35	9	27	106
Disposals and retirements	-	-	-	(12)	-	(12)
Balance at March 31, 2019	276	115	298	30	63	782
Net additions	13	6	67	19	53	158
Disposals and retirements	-	-	(3)	-	-	(3)
Balance at March 31, 2020	$ 289	$ 121	$ 362	$ 49	$ 116	$ 937
Accumulated Amortization						
Balance at April 1, 2018	$ -	$ (31)	$ (66)	$ -	$ -	$ (97)
Amortization expense	-	(21)	(62)	-	-	(83)
Disposals and retirements	-	-	-	-	-	-
Balance at March 31, 2019	-	(52)	(128)	-	-	(180)
Amortization expense	(1)	(17)	(62)	-	-	(80)
Disposals and retirements	-	-	1	-	-	1
Balance at March 31, 2020	$ (1)	$ (69)	$ (189)	$ -	$ -	$ (259)
Net carrying amounts						
At April 1, 2018	$ 247	$ 78	$ 197	$ 33	$ 36	$ 591
At March 31, 2019	$ 276	$ 63	$ 170	$ 30	$ 63	$ 602
At March 31, 2020	$ 288	$ 52	$ 173	$ 49	$ 116	$ 678

Land rights consist primarily of statutory rights of way acquired from the Province in perpetuity. 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Note 14: Other Non-Current Assets

(CAD$ in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Non-current receivables	**$**	**147**	$	148	$	194
Sinking funds		**217**		197		182
Non-current Site C prepaid expenses		**282**		250		244
Other		**9**		14		9
	$	**655**	$	609	$	629

Non-Current Receivables

Included in the non-current receivables balance are $129 million of receivables (2019 - $135 million, April 1, 2018 - $140 million) attributable to other contributions. 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:

(CAD$ in millions)	**March 31, 2020**		March 31, 2019		April 1, 2018	
	Carrying Value	**Weighted Average Effective Rate[1]**	Carrying Value	Weighted Average Effective Rate[1]	Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$ 137**	**1.3 %**	$ 126	2.9 %	$ 114	3.2 %
Other provincial government and crown corporation bonds	**80**	**1.0 %**	71	2.9 %	68	3.4 %
	$ 217		$ 197		$ 182	

[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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

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 (loss). The net movement in regulatory balances related to total comprehensive income is as follows:

(CAD$ in millions)	**2020**	2019
Net increase (decrease) in regulatory balances related to net income	**$ 1,065**	$ (1,120)
Net increase (decrease) in regulatory balances related to OCI	**(317)**	173
	$ 748	$ (947)

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.

(CAD$ in millions)	*As at April 1 2019*	*Addition / (Reduction)*	*Interest* [A]	*Amortization*	*Net Change* [B]	***As at March 31 2020***	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Non-Heritage Deferral Account	$ 141	$ 99	$ 6	$ (41)	$ 64	**$ 205**	Note D
Demand-Side Management	915	95	-	(103)	(8)	**907**	1-15
Debt Management	163	778	-	12	790	**953**	8-34
First Nations Provisions & Costs	505	21	3	(34)	(10)	**495**	4-9 Note G
Non-Current Pension Costs	486	(219)	-	(57)	(276)	**210**	7-14
Site C	491	(2)	19	-	17	**508**	Note E
CIA Amortization	83	(5)	-	-	(5)	**78**	20
Environmental Provisions & Costs	227	56	(2)	(21)	33	**260**	Note F, G
Smart Metering & Infrastructure	217	-	8	(30)	(22)	**195**	9
IFRS Pension	497	-	-	(38)	(38)	**459**	12
IFRS Property, Plant & Equipment	1,064	45	-	(30)	15	**1,079**	32-41
Storm Restoration Costs	58	(8)	1	(30)	(37)	**21**	Note F
Total Finance Charges	20	1	-	(10)	(9)	**11**	Note F
Real Property Sales	49	5	2	-	7	**56**	Note H
Other Regulatory Accounts	91	(3)	2	(41)	(42)	**49**	1-9
Total Regulatory Assets	5,007	863	39	(423)	479	**5,486**	
Regulatory Liabilities							
Heritage Deferral Account	485	82	13	(280)	(185)	**300**	Note D
Trade Income Deferral Account	261	69	9	(165)	(87)	**174**	Note D
Other Regulatory Accounts	4	4	-	(1)	3	**7**	2-5
Total Regulatory Liabilities	750	155	22	(446)	(269)	**481**	
Net Regulatory Asset	$ 4,257	$ 708	$ 17	$ 23	$ 748	**$ 5,005**	

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

(CAD$ in millions)	*As at April 1 2018*	*Addition / (Reduction)*	*Interest[A]*	*Amortization*	*Net Change[B]*	*As at March 31 2019*	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Non-Heritage Deferral Account	$ 525	$ (168)	$ 13	$ (229)	$ (384)	$ 141	Note D
Trade Income Deferral Account	128	(110)	1	(19)	(128)	-	Note D
Demand-Side Management	903	111	-	(99)	12	915	1-15
Debt Management	-	163	-	-	163	163	9-35
First Nations Provisions & Costs	518	22	4	(39)	(13)	505	5-9 Note G
Non-Current Pension Costs	304	240	-	(58)	182	486	8-13
Site C	472	-	19	-	19	491	Note E
CIA Amortization	88	(5)	-	-	(5)	83	21
Environmental Provisions & Costs	261	(1)	(2)	(31)	(34)	227	Note F, G
Smart Metering & Infrastructure	239	-	9	(31)	(22)	217	10
IFRS Pension	535	-	-	(38)	(38)	497	13
IFRS Property, Plant & Equipment	1,025	67	-	(28)	39	1,064	33-42
Rate Smoothing[C]	815	(815)	-	-	(815)	-	-
Storm Restoration Costs	47	19	2	(10)	11	58	Note F
Total Finance Charges	-	3	-	17	20	20	Note F
Real Property Sales	38	10	1	-	11	49	Note H
Other Regulatory Accounts	57	25	3	6	34	91	1-10
Total Regulatory Assets	5,955	(439)	50	(559)	(948)	5,007	
Regulatory Liabilities							
Heritage Deferral Account	423	95	19	(52)	62	485	Note D
Trade Income Deferral Account	-	214	3	44	261	261	Note D
Debt Management	158	(158)	-	-	(158)	-	9-35
Total Finance Charges	134	(50)	-	(84)	(134)	-	Note F
Other Regulatory Accounts	36	(7)	-	(25)	(32)	4	3-4
Total Regulatory Liabilities	751	94	22	(117)	(1)	750	
Net Regulatory Asset	$ 5,204	$ (533)	$ 28	$ (442)	$ (947)	$ 4,257	

[A] As permitted, interest charges were accrued to certain regulatory balances at a rate of 3.8% for the year ended March 31, 2020 (2019 – 4.0%).

[B] Net Change includes a net increase to net income of $1.07 billion (2019 – a net increase to net loss of $1.12 billion) and net decrease to other comprehensive income of $320 million (2019 – a net decrease to other comprehensive loss of $173 million).

[C] As at December 31, 2018, the entire balance of the Rate Smoothing Regulatory Account (RSRA) was expensed as BC Hydro determined that collection of the RSRA was no longer probable based on information received from the Province. This resulted in an operating expense of $1.04 billion during the year ended March 31, 2019. The operating expense was comprised of the $815 million balance in the account as at April 1, 2018 and $229 million deferred in the account from April 1, 2018 to December 31, 2018.

[D] The balances in these regulatory accounts are recovered in rates through the Deferral Account Rate Rider (DARR), which was an additional charge on customer bills. The DARR was 5 per cent for fiscal 2018 and fiscal 2019. In the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, BC Hydro proposed to reduce the DARR from 5 per cent to 0 per cent effective April 1, 2019 and to refund the forecast net credit balance in these accounts over the fiscal 2020 to fiscal 2021 test period.

[E] The recovery period for this account will be determined by the BCUC as part of a future regulatory proceeding once the Site C Project is placed into service.

[F] The balances 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. The balance at the end of fiscal 2019 will be recovered over the fiscal 2020 to fiscal 2021 test period.

[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 in this account 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.

Rate Regulation

In February 2019, BC Hydro filed an Application with the BCUC to approve its revenue requirements for a two year test period covering fiscal 2020 and fiscal 2021. Subsequently, BC Hydro submitted an Evidentiary Update in August 2019. The financial impact of the Evidentiary Update has been incorporated in these financial statements in accordance with the Company's rate regulation accounting policy, whereby BC Hydro defers amounts in advance of a final decision on the application by the BCUC based on management's estimate on the probability of acceptance and recovery in future rates.

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. Prior to fiscal 2020, these deferred variances were recovered in rates through the Deferral Account Rate Rider (DARR), which was an additional charge on customer bills. The DARR was set at 5 per cent for fiscal 2019. BC Hydro proposed to reduce the DARR from 5 per cent to 0 per cent effective April 1, 2019 and to refund the forecast net credit balance in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application in this account over the fiscal 2020 to fiscal 2021 test period.

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) and load (i.e., customer demand). Prior to fiscal 2020, these deferred variances were recovered in rates through the DARR. BC Hydro proposed to reduce the DARR from 5 per cent to 0 per cent effective April 1, 2019 and to refund the forecast balance in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application in this account over the fiscal 2020 to fiscal 2021 test period.

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. Prior to fiscal 2020, these deferred variances were recovered in rates through the DARR. BC Hydro proposed to reduce the DARR from 5 per cent to 0 per cent effective April 1, 2019 and to refund the forecast net credit balance in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application in this account over the fiscal 2020 to fiscal 2021 test period.

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. BC Hydro plans to seek BCUC approval to begin amortizing the balance of the Site C Regulatory Account once the assets are in service.

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. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

Rate Smoothing

As part of the 10 Year Rates Plan, the Rate Smoothing Regulatory Account was established with the objective of smoothing rate increases over the 10 Year Rates Plan period so that there is less volatility from year to year. As part of the Province’s Comprehensive Review Phase One, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.04 billion, resulting in a net loss for BC Hydro in fiscal 2019. BC Hydro is seeking BCUC approval to close this regulatory account in fiscal 2020.

Storm Restoration Costs

This account captures the difference between certain forecast storm restoration costs included in a revenue requirements application and actual storm restoration costs. Variances deferred during the current test period are recovered over the following test period.

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.

Total Finance Charges

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

Real Property Sales

This account captures variances between forecast and actual real property gains or losses from real estate sales. The balance in this account 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.

Other Regulatory Accounts

Other regulatory asset and liability accounts with individual balances less than $50 million include the following: Capital Project Investigation Costs, Arrow Water Systems Provisions, Arrow Water Systems (Costs), Dismantling Cost, Mining Customer Payment Plan, Foreign Exchange Gains and Losses, Post-Employment Benefit Current Pension Costs, Customer Crisis Fund and Amortization of Capital Additions.

Note 16: Accounts Payable and Accrued Liabilities

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Accounts payable	**$ 323**	$ 359	$ 259
Accrued liabilities	**1,074**	908	995
Current portion of lease liabilities (Note 19)	**79**	80	75
Current portion of other long-term liabilities (Note 24)	**109**	88	123
Dividend payable (Note 21)	**-**	59	159
Other	**41**	52	54
	$ 1,626	$ 1,546	$ 1,665

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

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.

The Company has a commercial paper borrowing program with the Province which is limited to $4.50 billion and is included in revolving borrowings. At March 31, 2020, the outstanding amount under the borrowing program was $2.74 billion (2019 - $2.95 billion, April 1, 2018 - $2.05 billion).

For the year ended March 31, 2020, the Company issued bonds for net proceeds of $1.61 billion (2019 - $2.42 billion) and a par value of $1.50 billion (2019 - $2.45 billion), a weighted average effective interest rate of 2.3 per cent (2019 - 3.0 per cent) and a weighted average term to maturity of 20.5 years (2019 - 19.8 years).

For the year ended March 31, 2020, the Company redeemed bonds with par value of $175 million (2019 – $1.29 billion).

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

(CAD$ in millions)	**March 31, 2020**					March 31, 2019					April 1, 2018				
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:															
2019	**$ -**	**$ -**	**$ -**	**$ -**	**-**	$ -	$ -	$ -	$ -	-	$ 1,030	$ 258	$ -	$ 1,288	4.4
2020	**-**	**-**	**-**	**-**	**-**	175	-	-	175	5.3	175	-	-	175	5.3
2021	**1,100**	**-**	**-**	**1,100**	**7.5**	1,100	-	-	1,100	7.5	1,100	-	-	1,100	7.5
2022	**526**	**-**	**-**	**526**	**7.8**	526	-	-	526	7.8	526	-	-	526	7.8
2023	**500**	**-**	**-**	**500**	**6.8**	500	-	-	500	6.8	500	-	-	500	6.8
2024	**200**	**-**	**-**	**200**	**5.9**	200	-	-	200	5.9	-	-	-	-	-
2025	**10**	**-**	**-**	**10**	**5.5**	-	-	-	-	-	-	-	-	-	-
1-5 years	**2,336**	**-**	**-**	**2,336**	**7.3**	2,501	-	-	2,501	7.2	3,331	258	-	3,589	6.2
6-10 years	**4,750**	**703**	**409**	**5,862**	**3.2**	3,960	668	395	5,023	3.1	2,860	644	418	3,922	3.2
11-15 years	**1,535**	**-**	**215**	**1,750**	**3.8**	1,610	-	207	1,817	4.5	1,610	-	219	1,829	4.5
16-20 years	**-**	**422**	**-**	**422**	**7.4**	-	400	-	400	7.4	-	387	-	387	7.4
21-25 years	**5,838**	**-**	**-**	**5,838**	**4.1**	3,273	-	-	3,273	4.3	3,273	-	-	3,273	4.3
26-30 years	**3,695**	**-**	**-**	**3,695**	**3.2**	5,985	-	-	5,985	3.5	2,565	-	-	2,565	3.7
Over 30 years	**1,060**	**-**	**-**	**1,060**	**2.7**	560	-	-	560	3.1	2,830	-	-	2,830	3.3
Bonds	**19,214**	**1,125**	**624**	**20,963**	**4.0**	17,889	1,068	602	19,559	4.1	16,469	1,289	637	18,395	4.3
Revolving borrowings	**1,686**	**1,057**	**-**	**2,743**	**1.5**	2,743	202	-	2,945	1.8	1,817	236	-	2,053	1.3
	20,900	**2,182**	**624**	**23,706**		20,632	1,270	602	22,504		18,286	1,525	637	20,448	
Adjustments to carrying value resulting from discontinued hedging activities	**10**	**22**	**-**	**32**		13	22	-	35		17	22	-	39	
Unamortized premium, discount, and issue costs	**(39)**	**(10)**	**(3)**	**(52)**		(143)	(10)	(4)	(157)		(107)	(11)	(5)	(123)	
	$ 20,871	**$ 2,194**	**$ 621**	**$ 23,686**		$ 20,502	$ 1,282	$ 598	$ 22,382		$ 18,196	$ 1,536	$ 632	$ 20,364	
Less: Current portion	**(2,786)**	**(1,057)**	**-**	**(3,843)**		(2,919)	(202)	-	(3,121)		(2,850)	(494)	-	(3,344)	
Non-current long-term debt	**$ 18,085**	**$ 1,137**	**$ 621**	**$ 19,843**		$ 17,583	$ 1,080	$ 598	$ 19,261		$ 15,346	$ 1,042	$ 632	$ 17,020	

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

The following foreign currency contracts were in place at March 31, 2020 in a net asset position of $143 million (2019 - $24 million, April 1, 2018 - $105 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Cross-Currency Swaps			
Euro dollar (€) to Canadian dollar - notional amount[1]	**€ 402**	€ 402	€ 402
Euro dollar to Canadian dollar - weighted average contract rate	**1.47**	1.47	1.47
Weighted remaining term	**8 years**	9 years	10 years
Foreign Currency Forwards			
United States dollar (US$) to Canadian dollar - notional amount[1]	**US$ 1,329**	US$ 741	US$ 1,012
United States dollar to Canadian dollar - weighted average contract rate	**1.30**	1.27	1.22
Weighted remaining term	**4 years**	8 years	7 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, 2020 with a net liability position of $1.01 billion (2019 – net liability of $285 million, April 1, 2018 – net asset of $83 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $5.03 billion of planned 10 and 30 year debt to be issued on dates ranging from June 2020 to June 2024.

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Bond Locks			
Canadian dollar - notional amount[1]	**$ 325**	$ 600	$ 1,250
Weighted forecast borrowing yields	**3.54%**	3.06%	3.17%
Weighted remaining term	**< 1 year**	< 1 year	< 1 year
Forward Swaps			
Canadian dollar - notional amount[1]	**$ 4,700**	$ 5,450	$ 3,625
Weighted forecast borrowing yields	**3.17%**	3.11%	2.76%
Weighted remaining term	**2 years**	2 years	2 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Note 18: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

(CAD$ in millions)		**2020**		2019
Restricted Cash	**$**	**94**	$	(32)
Accounts receivable and accrued revenue		**163**		(131)
Inventories		**(24)**		(23)
Prepaid expenses		**8**		(34)
Other non-current assets		**(35)**		18
Accounts payable and accrued liabilities		**(148)**		(10)
Unearned revenues and contributions in aid		**194**		160
Post-employment benefits		**(322)**		172
Other non-current liabilities		**20**		(24)
	$	**(50)**	$	96

Non-Cash Investing Transactions:

(CAD$ in millions)		**2020**		2019
Contributions in kind received for property, plant and equipment	**$**	**49**	$	42

Reconciliation for liabilities arising from financing activities:

(CAD$ in millions)	**Balance, March 31, 2019**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Payment**	**Balance March 31, 2020**
Long-term debt and revolving borrowings:							
Long-term debt	$ 19,437	$ 1,608	$ (175)	$ 79	$ (6)	$ -	$ 20,943
Revolving borrowings	2,945	10,484	(10,680)	-	(6)	-	2,743
Total long-term debt and revolving borrowings	22,382	12,092	(10,855)	79	(12)	-	23,686
Lease liability (Note 19)	1,550	-	-	-	82	(128)	1,504
Vendor financing liability	338	-	-	-	51	(41)	348
Debt-related derivative liability	263	-	-	-	712	(52)	923
	$ 24,533	$ 12,092	$ (10,855)	$ 79	$ 833	$ (221)	$ 26,461

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

(CAD$ in millions)	**Balance, April 1, 2018**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Proceeds (Payments)**	**Balance March 31, 2019**
Long-term debt and revolving borrowings:							
Long-term debt	$ 18,311	$ 2,418	$ (1,287)	$ 2	$ (7)	$ -	$ 19,437
Revolving borrowings	2,053	8,865	(7,981)	-	8	-	2,945
Total long-term debt and revolving borrowings	20,364	11,283	(9,268)	2	1	-	22,382
Lease liability (Note 19)	1,594	-	-	-	83	(127)	1,550
Vendor financing liability	320	-	-	-	44	(26)	338
Debt-related derivative liability	(182)	-	-	-	345	100	263
	$ 22,096	$ 11,283	$ (9,268)	$ 2	$ 473	$ (53)	$ 24,533

[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

Amounts recognized in profit or loss

(CAD$ in millions)	**2020**	2019
Interest on lease liabilities	**$ 51**	$ 52
Variable lease payments not included in the measurement of lease liabilities	**14**	12
Expenses relating to short-term leases and leases of low-value assets	**13**	14
	$ 78	$ 78

Amounts recognized in the statement of cash flows

(CAD$ in millions)	**2020**	2019
Total cash outflow for leases	**$ 155**	$ 153

Maturity analysis

($CAD in millions)	**March 31, 2020**	March 31, 2019
Maturity analysis - contractual undiscounted cash flows		
Less than 1 year	**$ 128**	**$ 110**
1 to 5 years	**403**	**360**
More than 5 years	**1,636**	**1,602**
Total Undiscounted Lease Liabilities	**$ 2,167**	**$ 2,072**

(CAD$ in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Current		**79**		80		75
Non-current		**1,425**		1,470		1,519
Total Lease Liabilities	**$**	**1,504**	$	1,550	$	1,594

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 of 13 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, 2020 was $12 million (2019 - $10 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, 2020 was $2 million (2019 - $2 million).

Other leases

The Company leases generating equipment. The generating equipment lease has a term of 3 years and an option to renew for an additional period of 2 years.

The Company also leases vehicles, office equipment and other equipment. These 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(q).

Note 20: Unearned Revenues and Contributions in Aid

(CAD$ in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Unearned revenues		**296**	$	230	$	210
Contributions in aid		**1,892**		1,762		1,633
		2,188		1,992		1,843
Less: Current portion, unearned revenues		**(40)**		(40)		(38)
Less: Current portion, contributions in aid		**(53)**		(47)		(47)
	$	**2,095**	$	1,905	$	1,758

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, 2020, March 31, 2019 and April 1, 2018 was as follows:

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Total debt, net of sinking funds	**$ 23,469**	$ 22,185	$ 20,182
Less: Cash and cash equivalents	**(115)**	(84)	(42)
Net Debt	**$ 23,354**	$ 22,101	$ 20,140
Retained earnings	**$ 5,638**	$ 4,933	$ 5,420
Contributed surplus	**60**	60	60
Accumulated other comprehensive loss	**(44)**	(47)	(34)
Total Equity	**$ 5,654**	$ 4,946	$ 5,446
Net Debt to Equity Ratio	**81 : 19**	82 : 18	79 : 21

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 reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

The payment for the year ended March 31, 2019 to the Province was $59 million and was paid in June 2019. The payment for the year ended March 31, 2020 was $nil.

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, 2018. The next valuation for funding purposes will be prepared as at December 31, 2021, and the results will be available in September 2022.

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, 2020 and 2019 is recognized in the following line items in the statement of comprehensive income (loss) prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions:

	Pension Benefit Plans		**Other Benefit Plans**		**Total**	
(CAD$ in millions)	**2020**	2019	**2020**	2019	**2020**	2019
Current service costs charged to personnel expenses - operating expenses	**$ 120**	$ 100	**$ 8**	$ 8	**$ 128**	$ 108
Net interest costs charged to finance costs	**53**	46	**10**	10	**63**	56
Total post-employment benefit plan expense	**$ 173**	$ 146	**$ 18**	$ 18	**$ 191**	$ 164

Actuarial gain recognized in other comprehensive income (loss) was $317 million (2019 – loss of $173 million).

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

(CAD$ in millions)	Pension Benefits Plans March 31, 2020	March 31, 2019	April 1, 2018	Other Benefits Plans March 31, 2020	March 31, 2019	April 1, 2018	Total March 31, 2020	March 31, 2019	April 1, 2018
Defined benefit obligation of funded plan	**$ (4,908)**	$ (5,035)	$ (4,654)	**$ -**	$ -	$ -	**$ (4,908)**	$ (5,035)	$ (4,654)
Defined benefit obligation of unfunded plans	**(167)**	(186)	(164)	**(199)**	(278)	(272)	**(366)**	(464)	(436)
Fair value of plan assets	**3,714**	3,747	3,616	**-**	-	-	**3,714**	3,747	3,616
Plan deficit	**$ (1,361)**	$ (1,474)	$ (1,202)	**$ (199)**	$ (278)	$ (272)	**$ (1,560)**	$ (1,752)	$ (1,474)
Represented by:									
Accrued benefit plan liability	**$ (1,361)**	$ (1,474)	$ (1,202)	**$ (199)**	$ (278)	$ (272)	**$ (1,560)**	$ (1,752)	$ (1,474)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2020 and fiscal 2019 in accordance with IFRIC 14, *The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction*.

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

(CAD$ in millions)	Pension Benefit Plans March 31, 2020	March 31, 2019	Other Benefit Plans March 31, 2020	March 31, 2019
Defined benefit obligation				
Opening defined benefit obligation	**$ 5,221**	$ 4,818	**$ 278**	$ 272
Current service cost	**120**	100	**8**	8
Interest cost on benefit obligations	**174**	191	**10**	10
Benefits paid[1]	**(193)**	(183)	**(10)**	(8)
Employee contributions	**43**	41	**-**	-
Actuarial losses (gains)[2]	**(290)**	254	**(87)**	(4)
Defined benefit obligation, end of year	**5,075**	5,221	**199**	278
Fair value of plan assets				
Opening fair value	**3,747**	3,616	**n/a**	n/a
Interest income on plan assets[3]	**121**	145	**n/a**	n/a
Employer contributions	**48**	44	**n/a**	n/a
Employee contributions	**43**	41	**n/a**	n/a
Benefits paid[1]	**(185)**	(176)	**n/a**	n/a
Actuarial gains (losses)[2,3]	**(60)**	77	**n/a**	n/a
Fair value of plan assets, end of year	**3,714**	3,747	**-**	-
Accrued benefit liability	**$ (1,361)**	$ (1,474)	**$ (199)**	$ (278)

[1] Benefits paid under Pension Benefit Plans include $18 million (2019 - $13 million) of settlement payments.

[2] Actuarial gains/losses are included in the Non-Current Pension Costs regulatory account and for fiscal 2020 are comprised of $60 million of experience losses on return on plan assets (2019 - $77 million) and $377 million of net actuarial gains (2019 - $250 million) on the benefit obligations due to discount rate decreases, medical services plan premium elimination, and actuarial experience losses.

[3] Actual income on defined benefit plan assets for the year ended March 31, 2020 was $61 million (2019 - $222 million).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

(d) The significant assumptions adopted in measuring the Company's accrued benefit obligations as at each March 31 year end and April 1 are as follows:

	Pension Benefit Plans			Other Benefit Plans		
	March 31, 2020	March 31, 2019	April 1, 2018	**March 31, 2020**	March 31, 2019	April 1, 2018
Discount rate						
Benefit cost	**3.33%**	3.56%	3.68%	**3.24%**	3.54%	3.92%
Accrued benefit obligation	**3.83%**	3.33%	3.56%	**3.73%**	3.24%	3.54%
Rate of return on plan assets	**3.33%**	3.56%	3.68%	**n/a**	n/a	n/a
Rate of compensation increase						
Benefit cost	**3.50%**	3.00%	3.00%	**3.50%**	3.00%	3.00%
Accrued benefit obligation	**3.50%**	3.50%	3.00%	**3.50%**	3.50%	3.00%
Health care cost trend rates						
Weighted average health care cost trend rate	**n/a**	n/a	n/a	**4.87%**	3.58%	4.57%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	n/a	**3.82%**	2.81%	3.47%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	n/a	**2040**	2040	2026

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 our 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 either valued by an independent valuator or priced using observable market inputs.

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

	Long Term Strategic Target Allocation	**Target Range**		**March 31,**	March 31,	April 1,
		Min	**Max**	**2020**	2019	2018
Fixed interest investments	20%	15%	35%	**27%**	26%	29%
Public equities	40%	30%	55%	**43%**	49%	50%
Real estate	15%	5%	20%	**12%**	10%	9%
Private equities	15%	5%	20%	**10%**	8%	6%
Infrastructure and renewable resources	10%	5%	15%	**8%**	7%	6%

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 2021 is expected to amount to $49 million. The expected benefit payments to be paid in fiscal 2021 in respect to the unfunded defined benefit plans are $15 million.

The following table presents the maturity profile of our defined benefit pension plan obligation:

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

Number of plan participants as at March 31, 2020		14,992
Actual benefit payments 2020	$	185
Benefits expected to be paid 2021	$	181
Benefits expected to be paid 2022	$	182
Benefits expected to be paid 2023	$	184
Benefits expected to be paid 2024	$	186
Benefits expected to be paid 2025	$	188
Benefits expected to be paid 2026-2029	$	768
Weighted average duration of defined benefits payments		15.1 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 2020.

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:

(CAD$ in millions)	One percentage point increase 2020	One percentage point decrease 2020
Effect on current service costs	$ -	$ -
Effect on defined benefit obligation	4	(5)

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

		2020	
(CAD$ in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	-553	-32
Discount rate	1% decrease	+ 710	+45
Longevity	1 year increase	+ 115	+ 3
Longevity	1 year decrease	- 119	- 3
Compensation	1% increase	+ 192	+ 20
Compensation	1% decrease	- 164	- 17

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 2019/20 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 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 statement of financial position at $217 million and $147 million respectively. The maximum credit risk exposure for the U.S. dollar sinking funds and non-current receivables as at March 31, 2020 is their fair value of $262 million and $159 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, 2020 and 2019 and April 1, 2018.

	March 31, 2020		March 31, 2019		April 1, 2018		**2020**	2019
(CAD$ in millions)	**Carrying Value**	**Fair Value**	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 (FVPTL):								
Cash equivalents - short-term investments	**$ 78**	**$ 78**	$ 50	$ 50	$ 31	$ 31	**$ 3**	$ 3
Amortized Cost:								
Cash	**37**	**37**	34	34	11	11	**-**	-
Restricted cash	**15**	**15**	109	109	77	77	**-**	-
Accounts receivable and accrued revenue	**770**	**770**	912	912	728	728	**-**	-
Non-current receivables	**147**	**159**	148	159	194	195	**7**	9
Sinking funds	**217**	**262**	197	220	182	201	**9**	9
Accounts payable and accrued liabilities	**(1,626)**	**(1,626)**	(1,546)	(1,546)	(1,665)	(1,665)	**-**	-
Revolving borrowings	**(2,743)**	**(2,743)**	(2,945)	(2,945)	(2,053)	(2,053)	**(47)**	(39)
Long-term debt (including current portion due in one year)	**(20,943)**	**(24,318)**	(19,437)	(22,480)	(18,311)	(20,814)	**(825)**	(815)
First Nations liabilities (non-current portion)	**(398)**	**(542)**	(391)	(640)	(399)	(652)	**(18)**	(17)
Lease liabilities (non-current portion)	**(1,425)**	**(1,425)**	(1,470)	(1,470)	(1,519)	(1,519)	**(51)**	(52)
Other liabilities	**(430)**	**(448)**	(419)	(434)	(409)	(416)	**(23)**	(18)

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, 2020 in a net asset position of $88 million (2019 – net asset $22 million, April 1, 2018 – net asset $99 million). Such contracts are used to hedge the principal on $US denominated long-term debt and the principal and coupon payments on Euro denominated long-term debt for which hedge accounting has been applied. The hedging instruments are effective in offsetting changes in the cash flows of the hedged item attributed to the hedged risk. The main source of hedge ineffectiveness in these hedges is credit risk.

($ amounts in millions)		**March 31, 2020**		March 31, 2019		April 1, 2018
Cross- Currency Hedging Swaps						
Euro dollar to Canadian dollar - notional amount[1]	**€**	**402**	€	402	€	402
Euro dollar to Canadian dollar - weighted average contract rate		**1.47**		1.47		1.47
Weighted remaining term		**8 years**		9 years		10 years
Foreign Currency Hedging Forwards						
United States dollar to Canadian dollar - notional amount[1]	**US$**	**573**	US$	573	US$	773
United States dollar to Canadian dollar - weighted average contract rate		**1.25**		1.25		1.19
Weighted remaining term		**10 years**		11 years		9 years

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

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

(CAD$ in millions)	**March 31, 2020 Fair Value**	March 31, 2019 Fair Value	April 1, 2018 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:			
Foreign currency contract assets (cash flow hedges for $US denominated long-term debt)	**$ 74**	$ 10	$ 59
Foreign currency contract liabilities (cash flow hedges for $US denominated long-term debt)	**-**	-	(8)
Foreign currency contract assets (cash flow hedges for €EURO denominated long-term debt)	**14**	12	48
	88	22	99
Non-Designated Derivative Instruments:			
Interest rate contract assets	**-**	25	180
Interest rate contract liabilities	**(1,011)**	(310)	(97)
Foreign currency contract assets	**55**	2	6
Commodity derivative assets	**54**	78	36
Commodity derivative liabilities	**(54)**	(72)	(73)
	(956)	(277)	52
Net (liability) asset	**$ (868)**	$ (255)	$ 151

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 statement of financial position as follows:

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Current portion of derivative financial instrument assets	**$ 106**	$ 79	$ 174
Current portion of derivative financial instrument liabilities	**(358)**	(89)	(114)
Derivative financial instrument assets, non-current	**92**	49	156
Derivative financial instrument liabilities, non-current	**(708)**	(294)	(65)
Net (liability) asset	**$ (868)**	$ (255)	$ 151

For designated cash flow hedges for the year ended March 31, 2020, there was a gain of $66 million (2019 – loss of $24 million). The effective portion was recognized in other comprehensive income and the ineffective portion was recognized in finance charges. For the year ended March 31, 2020, $63 million (2019 - $8 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses (2019 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $5.03 billion (2019 - $6.05 billion, April 1, 2018 - $4.90 billion), used to economically hedge the interest rates on future debt issuances, there was a $743 million decrease (2019 - $335 million decrease) in the fair value of these contracts for the year ended March 31, 2020. For interest rate contracts associated with debt issued, there was a $35 million decrease (2019 - $14 million increase) in the fair value of contracts that settled during the year ended March 31, 2020. The net decrease for the year ended March 31, 2020 of $778 million (2019 - $321 million) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had an asset balance of $953 million as at March 31, 2020.

Foreign currency contracts for cash management purposes not designated as hedges, for the year ended March 31, 2020, had a loss of $nil (2019 – gain of $1 million) recognized in finance charges. Foreign currency contracts associated with U.S. revolving borrowings not designated as hedges, for the year ended March 31, 2020, had a gain of $65 million (2019 - gain of $3 million) recognized in finance charges. These economic hedges offset $63 million of foreign exchange revaluation losses (2019 – losses of $1 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2020.

For commodity derivatives not designated as hedges, a net gain of $344 million (2019 - gain of $287 million) was recorded in trade revenue for the year ended March 31, 2020.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(CAD$ in millions)		**2020**		2019
Deferred inception gain, beginning of the year	**$**	**15**	$	23
New transactions		**21**		43
Amortization		**(29)**		(52)
Foreign currency translation (gain) loss		**-**		1
Deferred inception gain, end of the year	**$**	**7**	$	15

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:

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

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

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Current	**$ 368**	$ 592	$ 448
Past due (30-59 days)	**35**	31	32
Past due (60-89 days)	**11**	7	7
Past due (More than 90 days)	**4**	16	12
	418	646	499
Less: Allowance for doubtful accounts	**(6)**	(6)	(7)
	$ 412	$ 640	$ 492

At the end of each period, a review of the provision for doubtful accounts is performed. An assessment is performed based on the expected lifetime credit losses of domestic and trade accounts receivable at the statement of financial position date. The assessment is made by reference to age, status and risk of each receivable, current economic conditions including consideration of the impacts of COVID-19, and historical information. At March 31, 2020 there was a high degree of uncertainty and judgement regarding the impact that COVID-19 would have on credit risk and expected lifetime credit losses.

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 statement of financial position on a gross basis that are subject to derivative master netting agreements or similar agreements:

(CAD$ in millions)	Gross Derivative Instruments	Related Instruments Not Offset	Net Amount
As at March 31, 2020			
Derivative commodity assets	**$ 54**	**$ 3**	**$ 51**
Derivative commodity liabilities	**54**	**3**	**51**
As at March 31, 2019			
Derivative commodity assets	$ 78	$ 1	$ 77
Derivative commodity liabilities	72	1	71
As at April 1, 2018			
Derivative commodity assets	$ 36	$ 2	$ 34
Derivative commodity liabilities	73	2	71

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2020 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, 2020. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2020 has been used.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

(CAD$ in millions)	Carrying Value	Fiscal 2021	Fiscal 2022	Fiscal 2023	Fiscal 2024	Fiscal 2025	Fiscal 2026 *and thereafter*
Non-Derivative Financial Liabilities							
Total accounts payable and other payables (excluding interest accruals and current portion of lease obligations and First Nations liabilities)	$ 1,294	$ (1,294)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	23,906	(4,658)	(1,263)	(1,203)	(880)	(682)	(27,451)
Lease obligations	1,504	(128)	(125)	(93)	(93)	(93)	(1,636)
Other long-term liabilities	842	(96)	(94)	(66)	(62)	(60)	(1,807)
Total Non-Derivative Financial Liabilities	27,546	(6,176)	(1,482)	(1,362)	(1,035)	(835)	(30,894)
Derivative Financial Liabilities							
Other forward foreign exchange contracts designated at fair value	1						
Cash outflow		(66)	-	-	-	-	-
Cash inflow		65	-	-	-	-	-
Interest rate swaps used for hedging	1,011	(314)	(309)	(242)	(137)	(9)	-
Total Derivative Financial Liabilities	1,012	(315)	(309)	(242)	(137)	(9)	-
Total Financial Liabilities	28,558	(6,491)	(1,791)	(1,604)	(1,172)	(844)	(30,894)
Derivative Financial Assets							
Cross currency swaps used for hedging	(14)						
Cash outflow		(14)	(14)	(14)	(14)	(14)	(636)
Cash inflow		5	5	5	5	5	640
Forward foreign exchange contracts used for hedging	(74)						
Cash outflow		-	-	-	-	-	(719)
Cash inflow		-	-	-	-	-	806
Other forward foreign exchange contracts designated at fair value	(56)						
Cash outflow		(942)	-	-	-	-	-
Cash inflow		998	-	-	-	-	-
Net commodity derivatives	-	14	2	(2)	(3)	(3)	-
Total Derivative Financial Assets	(144)	61	(7)	(11)	(12)	(12)	91
Net Financial Liabilities	**$ 28,414**	**$ (6,430)**	**$ (1,798)**	**$ (1,615)**	**$ (1,184)**	**$ (856)**	**$ (30,803)**

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis
A $0.01 strengthening (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2020 would otherwise have a negative (positive) impact of $2 million on net income before movement in regulatory balances but as a result of regulatory accounting 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 interest rates, remain constant.

This sensitivity analysis has been determined assuming that the change in foreign exchange rates had occurred at March 31, 2020 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 statement of financial position date.

(b) Interest Rate Risk

Sensitivity analysis for variable rate non-derivative instruments
An increase (decrease) of 100-basis points in interest rates at March 31, 2020 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, 2020 would otherwise have a positive impact on net income of $820 million and a decrease of 100 basis points in interest rates at March 31, 2020 would otherwise have a negative impact on net income before movement in regulatory balances of $1.02 billion 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, 2020 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 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% 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 $7 million at March 31, 2020 (2019 - $10 million, April 1, 2018 - $6 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, 2020 and 2019, and April 1, 2018:

As at March 31, 2020 *(CAD$ in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 78	$ -	$ -	$ 78
Derivatives designated as hedges	-	88	-	88
Derivatives not designated as hedges	45	60	5	110
	$ 123	$ 148	$ 5	$ 276

As at March 31, 2020 *(CAD$ in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ -	$ -	$ -
Derivatives not designated as hedges	(33)	(1,016)	(17)	$ (1,066)
	$ (33)	$ (1,016)	$ (17)	$ (1,066)

As at March 31, 2019 *(CAD$ in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 50	$ -	$ -	$ 50
Derivatives designated as hedges	-	22	-	22
Derivatives not designated as hedges	64	38	4	106
	$ 114	$ 60	$ 4	$ 178

As at March 31, 2019 *(CAD$ in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ -	$ -	$ -
Derivatives not designated as hedges	(47)	(325)	(11)	(383)
	$ (47)	$ (325)	$ (11)	$ (383)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

As at April 1, 2018 *(CAD$ in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 31	$ -	$ -	$ 31
Derivatives designated as hedges	-	107	-	107
Derivatives not designated as hedges	17	201	5	223
	$ 48	$ 308	$ 5	$ 361

As at April 1, 2018 *(CAD$ in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(62)	(106)	(3)	(171)
	$ (62)	$ (114)	$ (3)	$ (179)

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. There were no transfers between Level 1 and 2 during the year (2019 - $1 million).

The following table reconciles the changes in the balance of financial instruments carried at fair value on the statement of financial position, classified as Level 3, for the years ended March 31, 2020 and 2019:

(CAD$ in millions)	
Balance as at April 1, 2019	**$ (7)**
Net gain recognized	31
New transactions	(15)
Transfer from Level 3 to Level 2	-
Existing transactions settled	(21)
Balance as at March 31, 2020	**$ (12)**

(CAD$ in millions)	
Balance as at April 1, 2018	**$ 2**
Net loss recognized	(31)
New transactions	8
Transfer from Level 3 to Level 2	-
Existing transactions settled	14
Balance as at March 31, 2019	**$ (7)**

There were no transfers between Level 3 and 2 during the year (2019 – no transfers).

During the year ended March 31, 2020, unrealized gains of $18 million (2019 – 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 include components of forward commodity prices and delivery or receipt volumes. A sensitivity analysis was prepared using the Company's assessment of reasonably possible changes in various components of forward prices and volumes of 10 per cent. Forward commodity prices used in determining Level 3 fair value at March 31, 2020 are $0-$108 per MWh and a 10 per cent increase/decrease in certain components of these prices would decrease/increase fair value by $1 million. A 10 per cent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $13 million.

Note 24: Other Non-Current Liabilities

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Provisions			
Environmental liabilities	**$ 309**	$ 284	$ 317
Decommissioning obligations	**77**	53	53
Other	**29**	30	70
	415	367	440
First Nations liabilities	**412**	410	401
Other contributions	**234**	238	242
Other liabilities	**430**	419	409
	1,491	1,434	1,492
Less: Current portion, included in accounts payable and accrued liabilities	**(109)**	(88)	(123)
	$ 1,382	$ 1,346	$ 1,369

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

(CAD$ in millions)	**Environmental**	**Decommissioning**	**Other**	**Total**
Balance at April 1, 2018	**$ 317**	**$ 53**	**$ 70**	**$ 440**
Made during the period	-	-	26	26
Used during the period	(32)	(1)	(67)	(100)
Reversed during the period	(9)	-	(1)	(10)
Changes in estimate	2	-	2	4
Accretion	6	1	-	7
Balance at March 31, 2019	**$ 284**	**$ 53**	**$ 30**	**$ 367**
Made during the period	-	-	10	10
Used during the period	(32)	(2)	-	(34)
Changes in estimate	52	25	(12)	65
Changes due to currency translation	-	-	1	1
Accretion	5	1	-	6
Balance at March 31, 2020	**$ 309**	**$ 77**	**$ 29**	**$ 415**

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, 2020, the undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2021 and 2045, is approximately $338 million and was determined based on current cost estimates. A range of discount rates between 0.4 per cent and 1.3 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 $95 million (2019 - $77 million, April 1, 2018 - $80 million), which will be settled between fiscal 2021 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 0.7 per cent and 1.3 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

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 $48.41 billion of which approximately $86 million relates to the purchase of natural gas and natural gas transportation contracts. The remaining commitments are at predetermined prices. Included in the total value of the long-term energy purchase agreements is $2.06 billion accounted for as a lease liability under Note 19. The total BC Hydro combined payments are estimated to be approximately $1.52 billion for less than one year, $6.26 billion between one and five years, and $40.63 billion for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $1.72 billion extending to 2034. The total Powerex energy purchase commitments are estimated to be approximately $512 million for less than one year, $1.19 billion between one and five years, and $24 million for more than five years. Powerex has energy sales commitments of $473 million extending to 2031 with estimated amounts of $314 million for less than one year, $147 million between one and five years, and $12 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 $847 million. Included in the total value of the lease agreements is $110 million accounted for as a lease liability under Note 19. Payments are $57 million for less than one year, $125 million between one and five years, and $666 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 $1.29 billion (2019 - $1.27 billion, April 1, 2018 – 1.17 billion), including amounts to secure pension plan solvency deficiency payments related to the registered pension plan. The total outstanding letters of credit also includes US $34 million (2019 - US $25 million, April 1, 2018 – US $12 million) in foreign denominated letters of credit.

Note 26: Related Party Transactions

Subsidiaries

The principal subsidiaries of BC Hydro are Powerex, Powertech, and Columbia.

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. Columbia provides construction services in support of certain BC Hydro capital programs.

All intercompany transactions and balances are eliminated upon consolidation.

Related Parties

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

(CAD$ in millions)	**March 31, 2020**	March 31, 2019	April 1, 2018
Consolidated Statement of Financial Position			
Prepaid expenses	**$ 83**	$ 87	$ 95
Right-of-use assets	**1,299**	1,330	1,376
Accounts payable and accrued liabilities	**69**	139	222
Lease liabilities	**1,399**	1,416	1,446

	2020	2019
Amounts incurred/accrued during the year include:		
Water rental fees	**293**	331
Cost of energy	**168**	225
Grants and Taxes	**146**	141
Interest	**872**	854
Derivatives	**41**	(110)
Dividend payments	**-**	59
Lease payments	**99**	96
Other	**17**	70

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, 2020, the aggregate exposure under this indemnity totaled $144 million (2019 - $49 million, April 1, 2018 - $293 million). The Company has not experienced any losses to date under this indemnity.

BC Hydro receives Low Carbon Fuel Credits from the Province and sells these 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.

(CAD$ in millions)	**2020**	2019
Short-term employee benefits	**$ 4**	$ 4
Post-employment benefits	**2**	1

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Note 27: Explanation of Adoption of IFRS 16

The Company previously recognized three long-term energy purchase agreements as finance leases. Under IFRS 16, these three long-term energy purchase agreements no longer meet the definition of a lease as the contract does not convey the right to control the use of the identified asset. In addition, the Company recognized certain long-term energy purchase agreements, office property agreements, and generating equipment agreements as a lease upon adoption of IFRS 16.

The following table summarizes the impact of the adjustments to the following periods:

Reconciliation of Consolidated Statement of Financial Position

	As at April 1, 2018			As at March 31, 2019		
(CAD$ in millions)	Pre-policy change	IFRS 16 Adjustment	**Post-policy change**	Pre-policy change	IFRS 16 Adjustment	**Post-policy change**
ASSETS						
Current Assets						
Cash and cash equivalents	$ 42	$ -	**$ 42**	$ 84	$ -	**$ 84**
Restricted cash	77	-	**77**	109	-	**109**
Accounts receivable and accrued revenue	728	-	**728**	912	-	**912**
Inventories	144	-	**144**	168	-	**168**
Prepaid expenses	152	(3)	**149**	153	(5)	**148**
Current portion of derivative financial instrument assets	174	-	**174**	79	-	**79**
	1,317	(3)	**1,314**	1,505	(5)	**1,500**
Non-Current Assets						
Property, plant and equipment	25,079	(640)	**24,439**	27,952	(618)	**27,334**
Right-of-use assets	-	1,526	**1,526**	-	1,466	**1,466**
Intangible assets	591	-	**591**	602	-	**602**
Derivative financial instrument assets	156	-	**156**	49	-	**49**
Other non-current assets	647	(18)	**629**	622	(13)	**609**
	26,473	868	**27,341**	29,225	835	**30,060**
Total Assets	27,790	865	**28,655**	30,730	830	**31,560**
Regulatory Balances	5,891	64	**5,955**	4,942	65	**5,007**
Total Assets and Regulatory Balances	$ 33,681	$ 929	**$ 34,610**	$ 35,672	$ 895	**$ 36,567**
LIABILITIES AND EQUITY						
Current Liabilities						
Accounts payable and accrued liabilities	$ 1,603	$ 62	**$ 1,665**	$ 1,478	$ 68	**$ 1,546**
Current portion of long-term debt	3,344	-	**3,344**	3,121	-	**3,121**
Current portion of unearned revenues and contributions in aid	85	-	**85**	87	-	**87**
Current portion of derivative financial instrument liabilities	112	2	**114**	89	-	**89**
	5,144	64	**5,208**	4,775	68	**4,843**
Non-Current Liabilities						
Long-term debt	17,020	-	**17,020**	19,261	-	**19,261**
Lease liabilities	652	867	**1,519**	642	828	**1,470**
Derivative financial instrument liabilities	66	(1)	**65**	296	(2)	**294**
Unearned revenues and contributions in aid	1,758	-	**1,758**	1,905	-	**1,905**
Post-employment benefits	1,474	-	**1,474**	1,752	-	**1,752**
Other non-current liabilities	1,369	-	**1,369**	1,346	-	**1,346**
	22,339	866	**23,205**	25,202	826	**26,028**
Total Liabilities	27,483	930	**28,413**	29,977	894	**30,871**
Regulatory Balances	751	-	**751**	748	2	**750**
Total Liabilities and Regulatory Balances	28,234	930	**29,164**	30,725	896	**31,621**
Shareholder's Equity						
Contributed surplus	60	-	**60**	60	-	**60**
Retained earnings	5,421	(1)	**5,420**	4,934	(1)	**4,933**
Accumulated other comprehensive loss	(34)	-	**(34)**	(47)	-	**(47)**
	5,447	(1)	**5,446**	4,947	(1)	**4,946**
Total Liabilities, Regulatory Balances, and Shareholder's Equity	$ 33,681	$ 929	**$ 34,610**	$ 35,672	$ 895	**$ 36,567**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Reconciliation of Consolidated Statement of Comprehensive Income (Loss)

	For the year ended March 31, 2019		
(CAD$ in millions)	Pre-policy change	IFRS 16 Adjustment	**Post-policy change**
Revenues			
Domestic	$ 5,432	$ -	**$ 5,432**
Trade	1,141	3	**1,144**
	6,573	3	**6,576**
Expenses			
Operating expenses	4,696	(8)	**4,688**
Finance charges	1,186	10	**1,196**
Net Income Before Movement in Regulatory Balances	691	1	**692**
Net movement in regulatory balances	(1,119)	(1)	**(1,120)**
Net Loss	(428)	-	**(428)**
OTHER COMPREHENSIVE INCOME (LOSS)			
Items That Will Be Reclassified to Net Loss			
Effective portion of changes in fair value of derivatives designated as cash flow hedges	(24)	-	**(24)**
Reclassification to income of derivatives designated as cash flow hedges	8	-	**8**
Foreign currency translation gains (losses)	3	-	**3**
Items That Will Not Be Reclassified to Net Loss			
Actuarial loss	(173)	-	**(173)**
Other Comprehensive Loss before movement in regulatory balances	(186)	-	**(186)**
Net movements in regulatory balances	173	-	**173**
Other Comprehensive Loss	(13)	-	**(13)**
Total Comprehensive Loss	$ (441)	-	**$ (441)**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2020 AND 2019

Reconciliation of Consolidated Statement of Cash Flows

For the year ended March 31, 2019

(CAD$ in millions)	Pre-policy change	IFRS 16 Adjustment	**Post-policy change**
Operating Activities			
Net loss	$ (428)	**-**	**$ (428)**
Regulatory account transfers	946	**1**	**947**
Adjustments for non-cash items:			
Amortization and depreciation expense	880	**69**	**949**
Unrealized losses on derivative financial instruments	286	**-**	**286**
Post-employment benefits expense	106	**-**	**106**
Interest accrual	854	**-**	**854**
Other items	38	**7**	**45**
	2,682	**77**	**2,759**
Changes in working capital and other assets and liabilities	100	**(4)**	**96**
Interest paid	(868)	**(52)**	**(920)**
Cash provided by operating activities	1,914	**21**	**1,935**
Investing Activities			
Property, plant and equipment and intangible asset expenditures	(3,766)	**-**	**(3,766)**
Cash used in investing activities	(3,766)	**-**	**(3,766)**
Financing Activities			
Long-term debt issued	2,418	**-**	**2,418**
Long-term debt retired	(1,287)	**-**	**(1,287)**
Receipt of revolving borrowings	8,865	**-**	**8,865**
Repayment of revolving borrowings	(7,981)	**-**	**(7,981)**
Payment to the Province	(159)	**-**	**(159)**
Payment of principal portion of lease liability	(54)	**(21)**	**(75)**
Other items	92	**-**	**92**
Cash provided by financing activities	1,894	**(21)**	**1,873**
Increase in cash and cash equivalents	42	**-**	**42**
Cash and cash equivalents, beginning of year	42	**-**	**42**
Cash and cash equivalents, end of year	$ 84	**-**	**84**

Note 28: Subsequent Events

Subsequent to March 31, 2020, the COVID-19 pandemic has continued to adversely impact global activity and has contributed to significant volatility and negative pressure in financial markets. The impact of COVID-19 has been rapidly evolving, and as cases of the virus have continued to be identified, many countries including Canada have reacted by instituting public health measures, including quarantines and restrictions on travel. Given the extent of the crisis, it is difficult to estimate the ultimate impact on BC Hydro.

On April 1, 2020 BC Hydro announced a series of customer relief measures related to COVID-19 and on April 2, 2020 the Province issued Order in Council No. 159 directing the BCUC to approve BC Hydro's

COVID-19 Customer Relief Program Application. The BCUC approved the COVID-19 Customer Relief Program Application on April 7, 2020.

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.

The COVID-19 pandemic may have a material impact on projects. As the evolution of the COVID-19 pandemic is uncertain and the date of resolution is unknown, cost and schedule impact scenarios continue to be assessed and refined. As a result, the potential impacts of the COVID-19 pandemic are not included in the information presented below.

Major Capital Projects (over $50 million)	**Targeted Completion Date (Calendar Year)**	**Project Cost to March 31, 2020 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Anticipated Total Capital Cost of Project ($ millions)**
Projects Recently Put Into Service				
Horne Payne Substation Upgrade Project This project expanded the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated feeder sections, and a new control building. This project increased the firm capacity of the substation, added needed feeder positions, facilitated the gradual conversion of the area supply voltage from 12kV to 25kV, and allowed for the implementation of an open-loop distribution system.	2019 In-Service	$69	$1	$70
John Hart Generating Station Replacement This project replaced the existing six-unit 126 MW generating station (in operation since 1947), added integrated emergency bypass capability to ensure reliable long-term generation, and mitigated earthquake risk and environmental risk to fish and fish habitat. **John Hart forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral.*	2019 In-Service	$975	$2	$977*
Cheakamus Unit 1 and Unit 2 Generator Replacement This project replaced the two generators at Cheakamus generating station (in operation since 1957), addressed their poor condition and known deficiencies, and increased the capacity of each unit from 70 MW to 90 MW.	2019 In-Service	$61	$1	$62

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Capital Cost of Project ($ millions)
Projects Recently Put Into Service				
Bridge River 2 Units 5 and 6 Upgrade Project This project replaced the two generators and other related equipment at Bridge River 2 and restored the historical operating capacity. These two generator units were placed in service in 1960, were in unsatisfactory condition and were unreliable.	2019 In-Service	$70	$8	$78

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Ongoing				
South Fraser Transmission Relocation Project* This project is intended to relocate certain sections of two 230kV transmission circuits (Circuit 2L62 and Circuit 2L58) from their present locations adjacent to Highway 99 and in the George Massey tunnel to accommodate the replacement of the tunnel. These two 230kV circuits form a critical part of BC Hydro's transmission network supplying power to customers in Richmond, Delta and the Greater Vancouver area. ***Construction work on the South Fraser Transmission Relocation project is currently suspended pending the government's review of the George Massey Tunnel replacement.*	TBD	$30	$46	$76
Downtown Vancouver Electricity Supply: West End Strategic Property Purchase This project is to acquire property rights to build and connect a new underground substation that will upgrade the aging electricity system in downtown Vancouver.	2020 Targeted In-Service	$67	$14	$81

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Fort St. John and Taylor Electric Supply This project will maintain adequate supply capability, reduce line losses and improve reliability to the loads in the Fort St. John and Taylor areas by re-terminating 138kV transmission lines at the new Site C switchyard, and by adding a 75 MVA transformer and new feeder positions.	2020 Targeted In-Service	$45	$8	$53
UBC Load Increase Stage 2 Project This project is on behalf of BC Hydro's customer, the University of British Columbia, to continue to reliably meet the growing electricity needs of its Point Grey campus and the surrounding community.	2021 Targeted In-Service	$40	$15	$55
Peace Region Electricity Supply (PRES) Project This project is needed to provide sufficient transmission system capacity to serve load growth and increase the reliability of electricity supply to existing customers in the South Peace region. This project will facilitate reductions in provincial greenhouse gas emissions by enabling electrification of natural gas production, processing, and compression. **The total cost represents the gross cost of the project and has not been netted for Federal Government contributions. The Federal Government's contribution amount is dependent on the final actual project costs and what costs are eligible under the agreement.* ***The contributions earned as of March 31, 2020 were $24M.*	2021 Targeted In-Service	$149**	$136	$285*

Major Capital Projects (over $50 million)	**Targeted Completion Date (Calendar Year)**	**Project Cost to Mar 31, 2020 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Approved Total Capital Cost of Project ($ millions)**
LNG Canada Load Interconnection Project This project is to facilitate the interconnection of LNG Canada's facility. A new double circuit 287kV transmission line will be constructed from Minette Substation (MIN) to LNG Canada's facility and system reinforcements at MIN will also be implemented. Under BC Hydro's standard tariffs, the customer is required to pay for a portion of this project's costs. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $24M.*	2021 Targeted In-Service	$35	$47	$82*
Bridge River 2 Upgrade Units 7 and 8 Project This project will replace the two generators and other related equipment to restore the historical operating capacity. Units 7 and 8 were placed into service in 1960, are unreliable and in poor and unsatisfactory condition, respectively.	2021 Targeted In-Service	$22	$64	$86
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.	2021 Targeted In-Service	$17	$34	$51

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Mica Replace Units 1 to 4 Generator Transformers Project This project will address the reliability and safety risks of the Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station, which are nearing end of life. There is a heightened reliability and safety risk from continuing to operate these transformers in an underground powerhouse as they age.	2022 Targeted In-Service	$30	$52	$82
G.M. Shrum G1 to 10 Control System Upgrade This project will replace the controls equipment, provide full remote control capability from the remote 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.	2022 Targeted In-Service	$46	$29	$75
Mount Lehman Substation Upgrade Project This project will increase the firm capacity of the Mount Lehman Substation to address safety and asset health concerns at both the Clayburn and Sumas Way substations.	2022 Targeted In-Service	$6	$53	$59

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Street Light Replacement Program The program will convert approximately 95,000 BC Hydro owned and maintained High Pressure Sodium (HPS) and Mercury Vapour (MV) 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.	2023 Targeted In-Service	$2	$78	$80
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	$8	$79	$87
Sperling Substation (SPG) 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.	2024 Targeted In-Service	$2	$52	$54

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ 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 forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. The amount includes a reserve of $708 million.* **** BC Hydro is working through the impacts of cost and schedule pressures as identified in its quarterly reporting to the BCUC, which includes, amongst others, the implementation of foundation enhancements and the COVID-19 pandemic.*	2024* Targeted In-Service	$5,127	$5,573	$10,700**

Significant IT Projects (over $20 million in total)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2020 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Total Capital Cost of Project ($ millions)
Ongoing				
Supply Chain Applications Project This project will replace BC Hydro's existing PassPort supply chain information technology (IT) system with an SAP-based IT system and make improvements to BC Hydro's supply chain business processes for third-party materials and service acquisitions.	2020 Targeted In-Service	$59	$9	$68

Appendix A: Additional Information

Organizational Overview

BC Hydro has offices throughout the communities of British Columbia and our employees operate in some of the most difficult terrain in the world. Our transmission system connects with transmission systems in Alberta and Washington State, which improves overall reliability of the system and provides opportunities for trade. Our largest offices are located in Burnaby, Cranbrook, Kamloops, Nanaimo, Prince George, Revelstoke, Surrey, Vancouver, Vernon and Victoria. Information about BC Hydro's organization and operating environment can be found at: http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html

Corporate Governance

BC Hydro is governed by a Board of Directors that is accountable to the Minister Responsible for the implementation of government direction. The Board's direction is implemented by management, who carries out the day-to-day operations of the Corporation under the supervision of the Chief Executive Officer. For more information on Corporate Governance, please refer to: http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

To support Director training and development, an orientation program is 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. The program utilizes materials and resources that inform Directors on the Corporation's corporate governance framework, its businesses, operations and current issues and strategies. Directors are also provided with ongoing development opportunities that include special site visits to provide them with additional insight into the Corporation's operations.

To promote awareness and understanding of the standards of conduct that BC Hydro expects, the Board of Directors has approved a Code of Conduct as well as Contractor Standards for Ethical Conduct. These documents provide general guidance on standards of conduct, including guidelines on conflict of interest, as well as requirements associated with confidential information, entertainment and gifts, environment and safety and use of BC Hydro property. The Code also allows exemptions from its requirements to be granted in extraordinary circumstances, and where it is clearly in the best interests of BC Hydro to do so. This is supplemented by guidance available from BC Hydro's Ethics Officer, as well as an independent Code Advisor for Directors and senior members of the executive.

Appendix B: Subsidiaries and Operating Segments

Active Subsidiaries

BC Hydro has created or retained a number of subsidiaries for various purposes, including holding licenses in other jurisdictions, to manage real estate holdings and to manage various risks.

As wholly-owned subsidiaries, and like BC Hydro itself, Powerex Corp. and Powertech Labs Inc. follow best practices in corporate governance and subsidiary activities align with BC Hydro's mandate, strategic priorities and fiscal plan.

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 $59 million to $436 million (2015/16 to 2019/20). The 2020/21-2022/23 Service Plan forecast includes annual net income from Powerex of approximately $180 million, based on the average earnings 2014/15 to 2018/19.

Board of Directors:

- Ken Peterson - Chair
- Len Boggio
- James Hatton
- Valerie Lambert
- 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 is internationally recognized as technical experts in a range of fields related to the electric utility and clean energy industries and offers services and solutions including performance and type testing, asset management solutions, engineering studies, and power system modelling and analysis to energy clients, including BC Hydro, and other sectors globally. Powertech is also a technical leader in hydrogen energy, providing certification, performance, and safety testing services for hydrogen components and systems, as well as the design and construction of innovative hydrogen vehicle refueling systems.

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

Over the last five years, Powertech's revenue has ranged from $36 million to $49 million (2015/16 to 2019/20) with a net income in the range of $3 million to $4 million.
The 2020/21 to 2022/23 Service Plan forecast includes annual net income from Powertech of approximately $4 million per year.

Board of Directors:

- Chris O'Riley – Chair
- Melissa Holland
- Kip Morison
- David Wong

Inactive 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.

All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. 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/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, 2020, these other subsidiaries consisted of the following:

1. British Columbia Hydro International Limited
2. British Columbia Power Exchange Corporation
3. British Columbia Power Export Corporation
4. British Columbia Transmission Corporation
5. Columbia Estate Company Limited*
6. Edmonds Centre Developments Limited*
7. Fauquier Water and Sewerage Corporation
8. Hydro Monitoring (Alberta) Inc.*
9. Victoria Gas Company Limited
10. Waneta Holdings (US) Inc.*
11. 1111472 BC Ltd.

Appendix C: Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2020**	2019[1,2]	2018[1,2]	2017[3]	2016[3]
Revenues					
Domestic	**$ 5,393**	$ 5,432	$ 5,223	$ 5,199	$ 5,056
Trade	**876**	1,144	731	675	601
Expenses					
Domestic energy costs	**1,742**	1,557	1,615	1,608	1,425
Trade energy costs	**628**	624	522	486	427
Other operating expenses[4]	**1,372**	1,292	1,302	1,025	937
Amortization and depreciation	**988**	949	817	1,232	1,241
Grants and taxes	**254**	266	241	234	220
Finance charges	**1,645**	1,196	824	605	752
	6,629	5,884	5,321	5,190	5,002
Net Income (Loss) Before Movement in Regulatory Balances	**(360)**	692	633		
Net movement in regulatory balances	**1,065**	(1,120)	51		
Net Income (Loss)	**$ 705**	$ (428)	$ 684	$ 684	$ 655
Property, Plant and Equipment, Right-of-Use Assets and Intangible Assets					
Property, Plant and Equipment	**$ 29,413**	$ 27,334	$ 24,439	$ 22,994	$ 21,385
Right-of-Use Assets	**1,405**	1,466	1,526	-	-
Intangible Assets	**678**	602	591	601	609
Net Book Value	**$ 31,496**	$ 29,402	$ 26,556	$ 23,595	$ 21,994
Property, Plant and Equipment and Intangible Asset Expenditures					
Sustaining	**$ 955**	$ 965	$ 1,190	$ 1,286	$ 1,136
Growth	**2,127**	2,861	1,283	1,158	1,170
Total Property, Plant and Equipment and Intangible Asset Expenditures [5]	**$ 3,082**	$ 3,826	$ 2,473	$ 2,444	$ 2,306
Net Long-Term Debt [6]	**$ 23,354**	$ 22,101	$ 20,140	$ 19,796	$ 18,002
Retained Earnings	**$ 5,638**	$ 4,933	$ 5,420	$ 4,822	$ 4,397
Debt to Equity Ratio	**81 : 19**	82 : 18	79 : 21	80 : 20	80 : 20

[1] The Company adopted IFRS 16, *Leases* (IFRS 16) in 2019/20 and restated the comparative periods 2018/19 and 2017/18. For additional information, refer to Note 27: Explanation of Adoption of IFRS 16 in the Audited Financial Statements.

[2] The Company adopted IFRS in 2018/19, and restated the comparative period 2017/18. For additional information, refer to Note 24: Explanation of Transition to IFRS in the Audited Financial Statements within the 2018/19 Annual Service Plan Report. Under IFRS, changes in regulatory balances are reported within the "net movements in regulatory balances".

[3] For 2015/16 and 2016/17 , the Company prepared its consolidated financial statements in accordance with the accounting principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, Regulated Operations, except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards). The changes in regulatory balance were reported within each financial statement line item.

[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	**2020**	2019	2018	2017	2016
Generating Capacity (megawatts)					
Hydroelectric	**11,932**	11,932	11,918	11,870	11,869
Thermal	**177**	177	180	183	175
Total	**12,109**	12,109	12,098	12,053	12,044
Peak One-Hour Integrated System Demand (megawatts)	**10,577**	10,045	9,651	10,194	9,602
Number of Customer Accounts					
Residential	**1,863,569**	1,833,097	1,803,752	1,776,503	1,751,296
Light industrial and commercial	**215,063**	212,446	210,673	207,802	205,615
Large industrial	**198**	195	190	191	185
Other	**3,396**	3,419	3,429	3,467	3,459
Trade	**159**	165	182	204	214
Total	**2,082,385**	2,049,322	2,018,226	1,988,167	1,960,769
Domestic Electricity Sold (gigawatt-hours)					
Residential	**17,993**	18,000	18,150	18,068	17,331
Light industrial and commercial	**18,692**	19,007	18,874	18,968	18,421
Large industrial	**13,398**	13,896	13,440	13,177	13,669
Surplus Sales	**182**	2,230	5,072	5,756	6,277
Other sales	**1,848**	1,510	1,637	1,683	1,602
Total	**52,113**	54,643	57,173	57,652	57,300

Revenues (in millions)

for the years ended March 31	**2020**	2019[1,2]	2018[1,2]	2017[3]	2016[3]
Residential	**$ 2,169**	$ 2,127	$ 2,097	$ 2,012	$ 1,842
Light industrial and commercial	**1,942**	1,925	1,860	1,800	1,685
Large industrial	**850**	873	811	770	766
Surplus Sales	**1**	115	139	133	174
Other sales	**431**	392	316	295	290
Total Domestic Revenue Before Regulatory Transfers	**5,393**	5,432	5,223	5,010	4,757
Regulatory transfers				189	299
Total Domestic	**5,393**	5,432	5,223	5,199	5,056
Trade - electricity and gas	**876**	1,144	731	675	601
Total	**$ 6,269**	$ 6,576	$ 5,954	$ 5,874	$ 5,657

Average Revenue (per kilowatt-hour) [4]

for the years ended or as at March 31	**2020**	2019	2018	2017	2016
Residential	**12.1¢**	11.8¢	11.6¢	11.1¢	10.6¢
Light industrial and commercial	**10.4**	10.1	9.9	9.5	9.1
Large industrial	**6.3**	6.3	6.0	5.8	5.6
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**9,735**	9,899	10,139	10,241	9,958
Lines In Service					
Distribution (kilometres)	**59,694**	59,095	59,222	59,078	58,765
Transmission (circuit kilometres)	**20,389**	20,385	20,306	20,278	20,176

1 The Company adopted IFRS 16, *Leases* (IFRS 16) in 2019/20 and restated the comparative periods 2018/19 and 2017/18. For additional information, refer to Note 27: Explanation of Adoption of IFRS 16 in the Audited Financial Statements.

2 The Company adopted IFRS in 2018/19, and restated the comparative period 2017/18. For additional information, refer to Note 24: Explanation of Transition to IFRS in the Audited Financial Statements within the 2018/19 Annual Service Plan Report. Under IFRS, changes in regulatory balances are reported within the "net movements in regulatory balances".

3 For 2015/16 and 2016/17 , the Company prepared its consolidated financial statements in accordance with the accounting principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, Regulated Operations, except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards). The changes in regulatory balance were reported within each financial statement line item.

4 Average revenues are before regulatory transfers.

TOTAL REQUIREMENTS FOR ELECTRICITY AND SOURCES OF SUPPLY

for the years ended March 31	**2020**			2019			2018			2017			2016		
	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	%
Electric System Deliveries															
Domestic	**12,109**	**52,113**	**70.9**	12,109	54,643	74.6	12,098	57,173	73.6	12,053	57,652	72.7	12,044	57,300	73.7
Electricity trade		**16,731**	**22.8**		14,139	19.3		15,046	19.4		16,740	21.1		14,732	18.9
		68,844	**93.7**		68,782	93.9		72,219	93.0		74,392	93.8		72,032	92.6
Line loss and system use		**4,651**	**6.3**		4,496	6.1		5,454	7.0		4,927	6.2		5,713	7.4
		73,495	**100.0**		73,278	100.0		77,673	100.0		79,319	100.0		77,745	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,778**	**12,605**	**17.2**	2,778	11,634	15.9	2,778	13,876	17.9	2,730	15,910	20.1	2,730	14,274	18.4
Revelstoke	**2,480**	**7,286**	**9.9**	2,480	8,408	11.5	2,480	9,082	11.7	2,480	8,264	10.4	2,480	9,805	12.6
Mica	**2,746**	**6,262**	**8.5**	2,746	7,625	10.4	2,746	8,561	11.0	2,746	7,397	9.3	2,747	9,451	12.2
Kootenay Canal	**583**	**2,377**	**3.2**	583	2,486	3.4	583	3,083	4.0	583	3,330	4.2	583	2,837	3.6
Peace Canyon	**694**	**3,051**	**4.2**	694	2,938	4.0	694	3,430	4.4	694	3,887	4.9	694	3,470	4.5
Seven Mile	**805**	**2,842**	**3.9**	805	3,137	4.3	805	3,460	4.5	805	3,326	4.2	805	2,666	3.4
Bridge River	**478**	**2,367**	**3.2**	478	1,996	2.7	478	2,216	2.9	478	2,504	3.2	478	2,582	3.3
Other	**1,368**	**3,592**	**4.9**	1,368	4,118	5.5	1,354	4,218	5.3	1,354	4,118	5.1	1,352	4,267	5.5
	11,932	**40,382**	**55.0**	11,932	42,342	57.7	11,918	47,926	61.7	11,870	48,736	61.4	11,869	49,352	63.5
Thermal generation															
Burrard	**0**	**0**	**0.0**	0	0	0.0	0	0	0.0	0	0	0.0	0	24	0.0
Other	**177**	**172**	**0.2**	177	190	0.3	180	91	0.1	183	74	0.1	175	191	0.2
Purchases under long-term commitments		**18,380**	**25.0**		18,256	24.9		18,399	23.7		17,753	22.4		18,441	23.7
Purchases under short-term commitments		**15,142**	**20.6**		12,645	17.3		10,658	13.7		13,009	16.4		10,713	13.8
Other		**(581)**	**(0.8)**		(155)	(0.2)		599	0.8		(253)	(0.3)		(976)	(1.2)
	12,109	**73,495**	**100.0**	12,109	73,278	100.0	12,098	77,673	100.0	12,053	79,319	100.0	12,044	77,745	100.0