British Columbia Hydro and Power Authority

2021/22

THIRD QUARTER REPORT

FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2021

BC Hydro
Power smart

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 three and nine months ended December 31, 2021 and should be read in conjunction with the MD&A presented in the 2020/21 Annual Service Plan Report, the 2020/21 Audited Consolidated Financial Statements and related notes of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three and nine months ended December 31, 2021.

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

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

Highlights

- Net income for the three and nine months ended December 31, 2021 was $263 million and $306 million, respectively, $36 million and $3 million lower than the same periods in the prior fiscal year.

- Domestic sales volumes for the three and nine months ended December 31, 2021 were 795 GWh (or 6 per cent) and 2,241 GWh (or 6 per cent), respectively, higher than the same periods in the prior fiscal year. These higher sales volumes were primarily weather-related (warmer temperatures in the summer and colder temperatures in December) and due to the economy gradually recovering from the impacts of COVID-19. There remains significant uncertainty associated with the pandemic's impacts on electricity demand.

- Capital expenditures, before contributions in aid of construction, for the three and nine months ended December 31, 2021 were $883 million and $2.59 billion, respectively, a $52 million and $204 million increase, respectively, over the prior fiscal year. The increase in capital expenditures for the three and nine months ended December 31, 2021, respectively, compared to the same period in the prior year was primarily due to Site C Project expenditures which can fluctuate based on the timing of work performed.

Consolidated Results of Operations

	For the three months ended December 31			*For the nine months ended December 31*		
(in millions)	**2021**	2020	Change	**2021**	2020	Change
Total Revenues	**$ 2,034**	$ 1,763	$ 271	**$ 5,454**	$ 4,512	$ 942
Net Income	**$ 263**	$ 299	$ (36)	**$ 306**	$ 309	$ (3)
Capital Expenditures	**$ 883**	$ 831	$ 52	**$ 2,587**	$ 2,383	$ 204
GWh Sold (Domestic)	**14,699**	13,904	795	**38,668**	36,427	2,241

(in millions)	*As at* ***December 31, 2021***	*As at* *March 31, 2021*	Change
Total Assets and Regulatory Balances	**$ 42,412**	$ 40,383	$ 2,029
Shareholder's Equity	**$ 6,678**	$ 6,367	$ 311
Retained Earnings	**$ 6,632**	$ 6,326	$ 306
Debt to Equity	**80 : 20**	80 : 20	n/a
Number of Domestic Customer Accounts	**2,148,841**	2,118,299	30,542

Revenues

For the three and nine months ended December 31, 2021, total revenues of $2.03 billion and $5.45 billion, respectively, were $271 million (or 15 per cent) and $942 million (or 21 per cent), respectively, higher than the same periods in the prior fiscal year. The increase over the same period in the prior fiscal year for the three months ended December 31, 2021 was due to higher trade revenues of $170 million and higher domestic revenues of $101 million. The increase over the same period in the prior fiscal year for the nine months ended December 31, 2021 was due to higher trade revenues of $597 million and higher domestic revenues of $345 million.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [1]	
for the three months ended December 31	**2021**	2020	**2021**	2020	**2021**	2020
Revenues						
Residential	**$ 707**	$ 652	**5,777**	5,441	**$ 122.38**	$ 119.83
Light industrial and commercial	**502**	481	**4,977**	4,733	**100.86**	101.63
Large industrial	**213**	199	**3,392**	3,221	**62.79**	61.78
Other sales	**127**	116	**553**	509	**-**	-
Domestic Revenues	**1,549**	1,448	**14,699**	13,904	**105.38**	104.14
Trade Revenues	**485**	315	**7,512**	8,896	**71.13**	42.46
Revenues	**$ 2,034**	$ 1,763	**22,211**	22,800	**$ 91.58**	$ 77.32

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [1]	
for the nine months ended December 31	**2021**	2020	**2021**	2020	**2021**	2020
Revenues						
Residential	**$ 1,617**	$ 1,492	**13,484**	13,037	**$ 119.92**	$ 114.44
Light industrial and commercial	**1,435**	1,324	**13,969**	13,106	**102.73**	101.02
Large industrial	**625**	543	**10,038**	9,131	**62.26**	59.47
Other sales	**346**	319	**1,177**	1,153	**-**	-
Domestic Revenues	**4,023**	3,678	**38,668**	36,427	**104.04**	100.97
Trade Revenues	**1,431**	834	**21,581**	23,792	**71.00**	39.58
Revenues	**$ 5,454**	$ 4,512	**60,249**	60,219	**$ 90.52**	$ 74.93

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

Domestic Revenues

Domestic revenues for the three months ended December 31, 2021 were $1.55 billion, $101 million (or 7 per cent) higher than the same period in the prior fiscal year. The increase was due to a combination of higher domestic sales and higher average rates that reflect the 1.0 per cent final rate increase as determined by the British Columbia Utilities Commission (BCUC) that was effective April 1, 2021.

Domestic revenues for the nine months ended December 31, 2021 were $4.02 billion, $345 million (or 9 per cent) higher than the same period in the prior fiscal year. The increase was due to the same reasons noted above, as well as lower revenues in the first six months of prior year due to the

COVID-19 relief program grants and waivers provided to customers. Domestic sales volumes were 2,241 GWh (or 6 per cent) higher than the same period in the prior fiscal year. This includes higher Large Industrial sales volumes, mainly in the pulp and paper and oil and gas sectors reflecting increased production and an improved energy market, as well as higher production in the chemical and wood manufacturing sectors, as economic conditions improved. Light Industrial and Commercial sales volumes were also higher due to increased business activity, as the economy gradually recovers from the impacts of COVID-19. Higher Residential sales volumes were primarily driven by warmer temperatures in the summer and colder temperatures in December.

Trade Revenues

Total trade revenues for the three and nine months ended December 31, 2021 were $485 million and $1.43 billion, respectively, an increase of $170 million (or 54 per cent) and $597 million (or 72 per cent), respectively, compared to the same periods in the prior fiscal year. The increase in trade revenue was primarily driven by higher average sale prices for the period.

Operating Expenses

For the three and nine months ended December 31, 2021, total operating expenses of $1.48 billion and $4.28 billion, respectively, were $259 million (or 21 per cent) and $593 million (or 16 per cent), respectively, higher than the same periods in the prior fiscal year.

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 three months ended December 31, 2021 were $780 million, $178 million (or 30 per cent) higher than the same period in the prior fiscal year. The increase was due to higher trade energy costs of $101 million and higher domestic energy costs of $77 million.

Total energy costs for the nine months ended December 31, 2021 were $2.21 billion, $471 million (or 27 per cent) higher than the same period in the prior fiscal year. The increase was due to higher trade energy costs of $317 million and higher domestic energy costs of $154 million.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the three months ended December 31	**2021**	2020	**2021**	2020	**2021**	2020
Energy Costs						
Water rental payments (hydro generation)[1]	**$ 86**	$ 70	**13,261**	14,064	**$ 6.49**	$ 4.98
Purchases from Independent Power Producers	**422**	391	**4,438**	3,945	**95.09**	99.11
Gas and transportation for thermal generation	**-**	1	**-**	-	**-**	-
Transmission charges and other expenses	**15**	10	**34**	32	**-**	-
Non-Treaty storage and Co-ordination agreements	**17**	(9)	**-**	-	**-**	-
Domestic Energy Costs	**540**	463	**17,733**	18,041	**30.45**	25.66
Trade Energy Costs	**240**	139	**6,178**	6,489	**51.92**	30.82
Energy Costs	**$ 780**	$ 602	**23,911**	24,530	**$ 32.62**	$ 24.54

	(in millions)		(gigawatt hours)		($ per MWh) [2]	
for the nine months ended December 31	**2021**	2020	**2021**	2020	**2021**	2020
Energy Costs						
Water rental payments (hydro generation)[1]	**$ 259**	$ 209	**32,782**	34,795	**$ 7.90**	$ 6.01
Purchases from Independent Power Producers	**1,182**	1,113	**13,519**	11,889	**87.43**	93.62
Gas and transportation for thermal generation	**3**	3	**-**	-	**-**	-
Transmission charges and other expenses	**31**	25	**80**	72	**-**	-
Non-Treaty storage and Co-ordination agreements	**3**	(26)	**-**	-	**-**	-
Domestic Energy Costs	**1,478**	1,324	**46,381**	46,756	**31.87**	28.32
Trade Energy Costs	**729**	412	**18,103**	17,404	**44.64**	24.46
Energy Costs	**$ 2,207**	$ 1,736	**64,484**	64,160	**$ 34.23**	$ 27.06

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

Domestic Energy Costs

Domestic energy costs for the three months ended December 31, 2021 were $540 million, $77 million (or 17 per cent) higher than the same period in the prior fiscal year. The increase in costs was primarily due to higher purchases from Independent Power Producers (IPPs) driven by higher energy deliveries mainly from two IPPs due to changes to their operations that increased the amount of energy available for sale to BC Hydro. The higher costs in the current period were also driven by higher Non-Treaty Storage and Co-ordination agreements costs and higher water rental costs. The higher Non-Treaty Storage and Co-ordination agreements costs were due to fewer net water releases in the current year compared to higher net water releases in the prior year. The higher water rental payments are based on the prior calendar year's hydro generation volumes and were driven by higher water inflows in the prior calendar year.

Domestic energy costs for the nine months ended December 31, 2021 were $1.48 billion, $154 million (or 12 per cent) higher than the same period in the prior fiscal year. The increase in costs was primarily due to the same reasons noted above.

Trade Energy Costs

Total trade energy costs for the three months ended December 31, 2021 were $240 million, an increase of $101 million (or 73 per cent) compared to the same period in the prior fiscal year. The increase was primarily driven by higher average purchase prices for the period.

Total trade energy costs for the nine months ended December 31, 2021 were $729 million, an increase of $317 million (or 77 per cent) compared to the same period in the prior fiscal year. The increase was primarily driven by higher average purchase prices and volumes for the period.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system for the nine months ending December 31, 2021 were slightly above average but lower than the same period in the prior fiscal year. The water inflows during the nine months ending December 31, 2021 were a combination of above average inflows in the Peace and Columbia basins, and below average inflows elsewhere in the system.

System energy storage is tracking above the ten-year historic average due to above average inflows in the Peace and Columbia basins. System energy storage at December 31, 2021 was lower than at December 31, 2020.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and nine months ended December 31, 2021 were $186 million and $547 million, respectively, comparable to the $177 million and $530 million, respectively, in the same periods in the prior fiscal year.

Materials and External Services

Materials and External Services primarily include materials, supplies, and contractor fees. Materials and external services for the three months ended December 31, 2021 were $158 million, an increase of $19 million (or 14 per cent) compared to the same period in the prior fiscal year. The increase was primarily due to higher spending in the current year to support compliance with the Mandatory Reliability Standards Program in British Columbia, higher bad debt expense, and higher spending on Demand-Side Management.

Materials and external services for the nine months ended December 31, 2021 were $470 million, an increase of $62 million (or 15 per cent) compared to the same period in the prior fiscal year. The increase was primarily due to higher spending in the current year to support compliance with the Mandatory Reliability Standards Program in British Columbia, higher spending on Demand-Side Management and higher spending in maintenance in the current year due to COVID-19 delays in the prior year.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and depreciation of right-of-use assets. Amortization and depreciation expense for the three and nine months ended December 31, 2021 were $269 million and $815 million, respectively, $16 million (6 per cent) and $63 million (8 per cent), respectively, higher than the same periods in the prior fiscal year. The higher depreciation expense for the three and nine months ended December was primarily due to additional property, plant and equipment placed in service and higher depreciation as a result of a change in the estimated useful lives of BC Hydro's property, plant, and equipment. The change in estimated useful lives was based on the recommendations from a depreciation study that was completed in the three months ended June 30, 2021.

Grants, Taxes and Other Costs

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.

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.

Total grants, taxes and other costs for the three months ended December 31, 2021 were $110 million, an increase of $37 million (or 51 per cent) compared to the same period in the prior fiscal year. The increase was primarily due to higher project and asset write-offs.

Total grants, taxes and other costs for the nine months ended December 31, 2021 were $295 million, a decrease of $16 million (or 5 per cent) compared to the same period in the prior fiscal year. The decrease was due to an increase in environmental provisions in the prior year related to the remediation of polychlorinated biphenyl (PCB) and asbestos, partially offset by higher taxes relating to trading activity in the United States and higher project and asset write-offs.

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 three and nine months ended December 31, 2021 were $19 million and $57 million, respectively, comparable to the $19 million and $53 million, respectively, in the same periods in the prior fiscal year.

Finance Charges

Finance charges for the three months ended December 31, 2021 were $345 million, an increase of $275 million (or 393 per cent) compared to the same period in 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 in the current year as compared to unrealized gains in the prior year.

Finance charges for the nine months ended December 31, 2021 were $780 million, an increase of $256 million (or 49 per cent) compared to the same period in 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 in the current year as compared to unrealized gains in the prior year, partially offset by lower interest rates for long-term debt that was refinanced and short-term borrowings.

Regulatory Transfers

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

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, including to better match costs and benefits for different generations of customers, and to defer 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:

(in millions)	For the three months ended December 31 **2021**	2020	For the nine months ended December 31 **2021**	2020
Cost of Energy Variance Accounts				
Heritage Deferral Account	**$ 11**	$ 22	**$ 24**	$ 149
Non-Heritage Deferral Account	**20**	74	**4**	(75)
Load Variance	**(45)**	18	**(89)**	(12)
Biomass Energy Program Variance	**(7)**	(3)	**(6)**	(12)
Low Carbon Fuel Credits Variance	**8**	-	**24**	-
Trade Income Deferral Account	**(99)**	(166)	**(276)**	(87)
	(112)	(55)	**(319)**	(37)
Forecast Variance Accounts				
Non-Current Pension Costs	**80**	(20)	**(89)**	553
Debt Management	**169**	(106)	**267**	(35)
Total Finance Charges	**9**	(17)	**22**	(42)
Real Property Sales	**(15)**	0	**(15)**	(10)
Other	**26**	(5)	**43**	23
	269	(148)	**228**	489
Capital-Like Accounts				
Demand-Side Management	**22**	16	**55**	41
Site C	**1**	-	**2**	(1)
IFRS Property, Plant & Equipment	**-**	6	**-**	17
	23	22	**57**	57
Non-Cash Accounts				
Environmental Provisions & Costs	**6**	2	**15**	80
First Nations Provisions & Costs	**5**	5	**10**	16
CIA Amortization	**(2)**	**(1)**	**(4)**	(4)
	9	6	**21**	92
Amortization of regulatory accounts	**(80)**	(35)	**(245)**	(108)
Interest on regulatory accounts	**1**	6	**9**	14
Net increase (decrease) in regulatory accounts	**$ 110**	$ (204)	**$ (249)**	$ 507

For the nine months ended December 31, 2021, there was a net reduction of $249 million to the Company's regulatory accounts compared to a net addition of $507 million in the same period in the prior fiscal year. The net regulatory asset balance as at December 31, 2021 was $4.03 billion compared to $4.28 billion as at March 31, 2021.

Net reductions to the regulatory accounts during the nine months ended December 31, 2021 included a $319 million reduction to the Cost of Energy Variance Accounts primarily due to higher trade income than planned, a $245 million reduction due to Amortization (which is the regulatory mechanism to recover the regulatory account balances in rates), and an $89 million reduction to the Non-Current Pension Costs Regulatory Account primarily due to a higher rate of return on pension plans assets. The reduction is partially offset by a $267 addition to the Debt Management Regulatory Account as a result of a net decrease in the fair value of interest rate hedges, and net additions of $128 million in the remaining regulatory accounts

BC Hydro has or has applied for regulatory mechanisms to collect all regulatory accounts in use or with balances at December 31, 2021 in rates over various periods.

Liquidity and Capital Resources

Cash flow provided by operating activities for the nine months ended December 31, 2021 was $1.21 billion, compared to $935 million in the same period in the prior fiscal year. The increase was mainly due to higher domestic revenues and higher trade income.

The long-term debt balance net of sinking funds as at December 31, 2021 was $26.27 billion compared to $24.78 billion as at March 31, 2021. The increase was mainly a result of an increase in net long-term bond issuances (net of redemptions) for net proceeds of $1.04 billion and an increase in revolving borrowings of $476 million. The increase was primarily to fund capital expenditures and to manage working capital.

Capital Expenditures

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

(in millions)	*For the three months ended December 31* **2021**	2020	*For the nine months ended December 31* **2021**	2020
Transmission lines and substation replacements and expansion	**$ 112**	$ 94	**$ 316**	$ 276
Generation replacements and expansion	**92**	82	**263**	213
Distribution system improvements and expansion	**135**	140	**420**	406
General, including technology, vehicles and buildings	**46**	52	**109**	171
Site C Project	**498**	463	**1,479**	1,317
Total Capital Expenditures	**$ 883**	$ 831	**$ 2,587**	$ 2,383

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

The increase in capital expenditures of $52 million and $204 million, respectively, for the three and nine months ended December 31, 2021 compared to the same periods in the prior fiscal year was primarily due to Site C Project expenditures which can fluctuate based on the timing of work performed. Capital expenditures for the three and nine months ended December 31, 2021 were within planned amounts.

Transmission lines and substation replacements and expansion include capital expenditures on transmission overhead lines, cables, substations, telecommunication systems, and transmission power equipment. Key capital expenditures include the following projects/programs: Transmission Wood Structure and Framing Replacements, Mount Lehman Substation Upgrade, Capilano Substation Upgrade, Various Sites – NERC CIP-003v7 Implementation, 5L063 Telkwa Relocation, and LNG Canada Load Interconnection.

Generation replacements and expansion include capital expenditures on dam safety projects as well as on generating facilities and related major equipment such as turbines, generators, governors, exciters, transformers, and circuit breakers. Key capital expenditures include the following projects: Waneta U3 Life Extension, Puntledge Recoat Interior and Exterior of Steel Penstock, Fort Nelson – Unit 1 Engine Replacement, John Hart Dam Seismic Upgrade, and Mica Replace Units 1 to 4 Generator Transformers.

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

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

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

Rate Regulation

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

Regulatory Applications

On August 31, 2021, BC Hydro filed a three-year revenue requirements application with the BCUC, seeking an annual average bill increase of 1.1 per cent for the next three years. To recover our planned expenditures, BC Hydro requested a net bill decrease of 1.4 per cent on April 1, 2022, followed by net bill increases of 2.0 per cent on April 1, 2023 and 2.7 per cent on April 1, 2024. The Application sought additional operating funding for investments in Mandatory Reliability Standards, vegetation management and cybersecurity. The Application also sought funding for BC Hydro's Electrification Plan to increase low carbon electrification, attract additional customer load and connect customers more efficiently. A decision on the application is expected in late calendar 2022 or early calendar 2023.

On August 31, 2021, BC Hydro filed an application for a new Mandatory Reliability Standards Costs Regulatory Account for fiscal 2022 to capture certain actual unplanned costs expected to be incurred in fiscal 2022 associated with compliance of mandatory reliability standards. On February 8, 2022, the BCUC issued Ordered No. G-26-22 and approved BC Hydro's request to establish the Mandatory Reliability Standards Costs Regulatory Account.

Performance Based Regulation

On December 21, 2021 the BCUC issued its decision on Performance Based Regulation directing BC Hydro to file, no later than December 31, 2023, a proposal for a Performance Based Regulation Plan for BC Hydro covering years starting with Fiscal 2026. The BCUC has directed that this proposal includes, among other things, a Plan covering at least five years and proposed indices/formulas that would be used to set controllable costs where possible.

Risk Management

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

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of BCUC-approved regulatory accounts. Regulatory accounts assist in matching costs and benefits for different generations of customers and to defer for future recovery in rates the differences between planned and actual costs or revenues that arise due to uncontrollable events. BC Hydro's approach to the recovery of its regulatory accounts is included in the Fiscal 2023 – Fiscal 2025 Revenue Requirements Application.

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue, domestic and trade cost of energy, and finance charges. These are influenced by several elements, which generally fall into the following six categories: hydro generation, customer demand, electricity/gas trade margins, deliveries from electricity purchase agreement contracts, interest rates, and discount rates for post-employment benefit plans. Neither a high nor a low value of any of these individual drivers is intrinsically positive or negative for BC Hydro's financial results. It is the specific combination of these drivers in any given year which has an impact.

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

In June 2021, the Province's Treasury Board approved a revised $16 billion budget and a new in-service date of 2025 for the Site C Project. The newly-approved budget and schedule addressed significant cost pressures and delays faced by the Site C Project due to the COVID-19 pandemic, as well as the right bank foundation enhancements and other cost pressures prior to the COVID-19 pandemic. The Site C Project continues to manage significant potential risks including the ongoing continuation of the COVID-19 pandemic, commercial negotiations with contractors and remaining procurements, availability of skilled workers, and the issuance of provincial permits required for the completion of the Project. As of December 31, 2021, BC Hydro has substantially implemented all the recommended actions in the Milburn Report.

Demand for Electricity

Domestic load volumes for the nine months ended December 31, 2021 were approximately 6 per cent higher than the same period in the prior fiscal year. Compared to plan, load volumes were 2 per cent higher for the nine months ended December 31, 2021. This increase was primarily weather-related (warmer temperatures in the summer and colder temperatures in December) and due to global, national and provincial economies recover from the COVID-19 pandemic. The uncertainty associated with the pandemic may continue to impact electricity demand.

This section should be read in conjunction with the risks disclosed in the Risk Management section in the Management's Discussion and Analysis presented in the 2020/21 Annual Service Plan Report for the year ended March 31, 2021. In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives is outlined at www.bchydro.com/serviceplan.

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 2021 included net income for 2021/22 at $712 million which is consistent with the amount required by Order in Council No. 172.

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.

BC Hydro provided the Province with an updated forecast which has been included in BC Hydro's 2022/23 – 2024/25 Service Plan and which forecasts a net income of $681 million for 2021/22 and $712 million for 2022/23. This updated forecast in 2021/22 is $31 million (or 4 per cent) lower than the net income in the previous Service Plan primarily due to higher forecast Operating Expenses.

The COVID-19 pandemic continues to adversely impact global activity and has contributed to significant volatility in financial markets. The pandemic could have a sustained adverse impact on economic and market conditions and could adversely impact BC Hydro's future performance if it were to cause a prolonged decrease in customer load, volatility in electricity/gas trade margins and interest rates, difficulty accessing debt, project delays and project cost escalations.

While BC Hydro engages in emergency preparedness (including business continuity planning) to mitigate risks, the persisting uncertainty of this situation limits the ability to predict the ultimate adverse impact of COVID-19 on BC Hydro's performance, financial condition, results of operations and cash flows.

Unaudited Condensed Consolidated Interim Statements of Comprehensive Income

(in millions)	*For the three months ended December 31* **2021**	2020	*For the nine months ended December 31* **2021**	2020
Revenues (Note 3)				
Domestic	**$ 1,549**	$ 1,448	**$ 4,023**	$ 3,678
Trade	**485**	315	**1,431**	834
Revenues	**2,034**	1,763	**5,454**	4,512
Expenses				
Operating expenses (Note 4)	**1,484**	1,225	**4,277**	3,684
Finance charges (Note 5)	**345**	70	**780**	524
Net Income Before Movement in Regulatory Balances	**205**	468	**397**	304
Net movement in regulatory balances (Note 9)	**58**	(169)	**(91)**	5
Net Income	**263**	299	**306**	309
Other Comprehensive Income				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 14)	**(17)**	(32)	**(11)**	(57)
Reclassification to income of derivatives designated as cash flow hedges (Note 14)	**14**	36	**9**	75
Foreign currency translation losses	**-**	(19)	**(5)**	(42)
Items That Will Not Be Reclassified Subsequently to Net Income				
Actuarial gain (loss) on post employment benefits	**(53)**	47	**170**	(473)
Other Comprehensive Income (Loss) before movement in regulatory balances	**(56)**	**32**	**163**	**(497)**
Net movements in regulatory balances (Note 9)	**52**	(35)	**(158)**	502
Other Comprehensive Income (Loss)	**(4)**	(3)	**5**	5
Total Comprehensive Income	**$ 259**	$ 296	**$ 311**	$ 314

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Unaudited Condensed Consolidated Interim Statements of Financial Position

(in millions)		As at December 31 2021		As at March 31 2021
Assets				
Current Assets				
Cash and cash equivalents	**$**	**147**	$	37
Restricted cash		**87**		6
Accounts receivable and accrued revenue		**862**		827
Inventories (Note 7)		**264**		182
Prepaid expenses		**50**		152
Current portion of derivative financial instrument assets (Note 14)		**155**		87
		1,565		1,291
Non-Current Assets				
Property, plant and equipment (Note 8)		**33,451**		31,677
Right-of-use assets		**1,244**		1,317
Intangible assets (Note 8)		**698**		688
Derivative financial instrument assets (Note 14)		**79**		30
Other non-current assets (Note 10)		**550**		605
		36,022		34,317
Total Assets	**$**	**37,587**	$	35,608
Regulatory Balances (Note 9)		**4,825**		4,775
Total Assets and Regulatory Balances	**$**	**42,412**	$	40,383
Liabilities and Equity				
Current Liabilities				
Accounts payable and accrued liabilities	**$**	**1,384**	$	1,589
Current portion of long-term debt (Note 11)		**3,778**		3,329
Current portion of unearned revenues and contributions in aid		**102**		93
Current portion of derivative financial instrument liabilities (Note 14)		**259**		235
		5,523		5,246
Non-Current Liabilities				
Long-term debt (Note 11)		**22,698**		21,651
Lease liabilities		**1,303**		1,352
Derivative financial instrument liabilities (Note 14)		**206**		78
Unearned revenues and contributions in aid		**2,374**		2,261
Post-employment benefits (Note 13)		**1,461**		1,528
Other non-current liabilities (Note 15)		**1,372**		1,402
		29,414		28,272
Total Liabilities		**34,937**		33,518
Regulatory Balances (Note 9)		**797**		498
Total Liabilities and Regulatory Balances		**35,734**		34,016
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**6,632**		6,326
Accumulated other comprehensive loss		**(14)**		(19)
		6,678		6,367
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$**	**42,412**	$	40,383

Commitments (Note 8)

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Unaudited Condensed Consolidated Interim Statements of Changes in Equity

(in millions)	Cumulative Translation Reserve	Unrealized Income (Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2020	$ -	$ (44)	$ (44)	$ 60	$ 5,638	$ 5,654
Comprehensive Income (Loss)	(13)	18	5	-	309	314
Balance as at December 31, 2020	$ (13)	$ (26)	$ (39)	$ 60	$ 5,947	$ 5,968
Balance as at April 1, 2021	$ (19)	$ -	$ (19)	$ 60	$ 6,326	$ 6,367
Comprehensive Income (Loss)	7	(2)	5	-	306	311
Balance as at December 31, 2021	$ (12)	$ (2)	$ (14)	$ 60	$ 6,632	$ 6,678

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Unaudited Condensed Consolidated Interim Statements of Cash Flows

For the nine months ended December 31 (in millions)	**2021**	2020
Operating Activities		
Net income	**$ 306**	$ 309
Regulatory account transfers (Note 9)	**91**	(5)
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 6)	**815**	752
Unrealized losses on derivative financial instruments	**171**	76
Post-employment benefit plan expenses	**107**	95
Interest accrual	**587**	635
Other items	**55**	44
	2,132	1,906
Changes in working capital and other assets and liabilities (Note 16)	**(110)**	(118)
Interest paid	**(809)**	(853)
Cash provided by operating activities	**1,213**	935
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(2,380)**	(2,178)
Cash used in investing activities	**(2,380)**	(2,178)
Financing Activities		
Long-term debt issued (Note 11)	**1,569**	2,502
Long-term debt retired (Note 11)	**(526)**	(1,100)
Receipt of revolving borrowings	**6,656**	6,598
Repayment of revolving borrowings	**(6,179)**	(6,328)
Payment of principal portion of lease liability	**(72)**	(69)
Settlement of hedging derivatives	**(151)**	(369)
Other items	**(20)**	(19)
Cash provided by financing activities	**1,277**	1,215
Increase (decrease) in cash and cash equivalents	**110**	(28)
Cash and cash equivalents, beginning of period	**37**	115
Cash and cash equivalents, end of period	**$ 147**	$ 87

Supplemental Disclosure of Cash Flow Information (Note 16)

See accompanying Notes to the Unaudited Condensed Consolidated Interim 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 condensed consolidated interim financial statements (interim financial statements) of BC Hydro include the accounts of BC Hydro and its principal wholly-owned operating subsidiaries Powerex Corp. (Powerex), and Powertech Labs Inc. (Powertech), (collectively with BC Hydro, the Company). All intercompany transactions and balances are eliminated on consolidation.

Note 2: Basis of Presentation

Basis of Accounting

These interim financial statements have been prepared by management in accordance with principles of IAS 34, *Interim Financial Reporting* and were prepared using the same accounting policies as described in BC Hydro's 2020/21 Annual Service Plan Report. These interim financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2020/21 Annual Service Plan Report.

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

These interim financial statements were approved on behalf of the Board of Directors on February 9, 2022.

Note 3: Revenue

The Company disaggregates revenue by revenue type 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 UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2021

(in millions)	*For the three months ended December 31* **2021**	2020	*For the nine months ended December 31* **2021**	2020
Domestic				
Residential	**$ 707**	$ 652	**$ 1,617**	$ 1,492
Light industrial and commercial	**502**	481	**1,435**	1,324
Large industrial	**213**	199	**625**	543
Other sales	**127**	116	**346**	319
Total Domestic	**1,549**	1,448	**4,023**	3,678
Total Trade[1]	**485**	315	**1,431**	834
Total Revenue	**$ 2,034**	$ 1,763	**$ 5,454**	$ 4,512

[1] Includes revenue recognized under IFRS 9, *Financial Instruments* of $193 million and $562 million for the three and nine months ended December 31, 2021, respectively (2020 - $199 million and $436 million, respectively).

Note 4: Operating Expenses

(in millions)	*For the three months ended December 31* **2021**	2020	*For the nine months ended December 31* **2021**	2020
Electricity and gas purchases	**$ 636**	$ 481	**$ 1,743**	$ 1,367
Water rentals	**86**	70	**259**	209
Transmission charges	**58**	51	**205**	160
Personnel expenses	**186**	177	**547**	530
Materials and external services	**158**	139	**470**	408
Amortization and depreciation (Note 6)	**269**	253	**815**	752
Grants, taxes and other costs	**110**	73	**295**	311
Less: Capitalized costs	**(19)**	(19)	**(57)**	(53)
	$ 1,484	$ 1,225	**$ 4,277**	$ 3,684

Note 5: Finance Charges

(in millions)	*For the three months ended December 31* **2021**	2020	*For the nine months ended December 31* **2021**	2020
Interest on long-term debt	**$ 198**	$ 203	**$ 587**	$ 635
Interest on lease liabilities	**11**	12	**34**	36
Interest on defined benefit plan obligations	**14**	16	**42**	48
Mark-to-market losses (gains) on derivative financial instruments	**169**	(107)	**269**	(37)
Capitalized interest	**(67)**	(57)	**(191)**	(169)
Other	**20**	3	**39**	11
	$ 345	$ 70	**$ 780**	$ 524

Note 6: Amortization and Depreciation

(in millions)	*For the three months ended December 31* **2021**	2020	*For the nine months ended December 31* **2021**	2020
Depreciation of property, plant and equipment	**$ 224**	$ 208	**$ 676**	$ 620
Depreciation of right-of-use assets	**23**	24	**71**	71
Amortization of intangible assets	**22**	21	**68**	61
	$ 269	$ 253	**$ 815**	$ 752

Note 7: Inventories

(in millions)	***As at December 31*** **2021**	*As at March 31* 2021
Materials and supplies	**$ 184**	$ 178
Natural gas trading inventories	**80**	4
	$ 264	$ 182

Note 8: Property, Plant and Equipment and Intangible Assets

Property, plant and equipment and intangible asset additions, before contributions in aid of construction, for the three and nine months ended December 31, 2021 were $883 million and $2.59 billion, respectively (2020 - $831 million and $2.38 billion, respectively).

As of December 31, 2021, the Company had contractual commitments to spend $2.02 billion on major property, plant and equipment projects (for individual projects greater than $50 million).

Note 9: Rate Regulation

The BC Utilities Commission (BCUC) issued its decision (Decision) on BC Hydro's Fiscal 2022 Revenue Requirements Application on June 17, 2021. In its Decision, the BCUC included three compliance directives impacting rates, which resulted in a Fiscal 2022 net bill increase of 1.00 per cent rather than the 1.16 per cent increase requested in the application. The BCUC Decision directed BC Hydro to establish a new Depreciation Study regulatory account and approved the closure of the Rock Bay Remediation regulatory account. As a result of the Decision, BC Hydro requested a new Low Carbon Fuel Credits Variance regulatory account in the Fiscal 2022 Revenue Requirements Application Compliance Filing. The financial impact of the Decision has been incorporated in these financial statements.

In August 2021, BC Hydro applied for BCUC approval of a new Mandatory Reliability Standards Costs Regulatory Account. In February 2022, the BCUC approved BC Hydro's request to establish this regulatory account. The financial impact of the new Mandatory Reliability Standards Costs Regulatory Account has been incorporated in these financial statements.

The Low Carbon Fuel Credits Variance, Depreciation Study and Mandatory Reliability Standards Costs regulatory accounts were included within other regulatory accounts – assets in the table below.

Regulatory Accounts

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

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2021**	2020	**2021**	2020
Net increase (decrease) in regulatory balances related to net income	**$ 58**	$ (169)	**$ (91)**	$ 5
Net increase (decrease) in regulatory balances related to OCI	**52**	(35)	**(158)**	502
	$ 110	$ (204)	**$ (249)**	$ 507

For each regulatory account, the amount reflected in the Net Change column in the following table 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.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2021

(in millions)	*As at April 1 2021*	*Addition (Reduction)*	*Interest*[1]	*Amortization*	*Net Change*[2]	***As at December 31 2021***
Regulatory Assets						
Heritage Deferral	$ 65	$ 24	$ 1	$ -	$ 25	**$ 90**
Load Variance	110	(89)	2	-	(87)	**23**
Demand-Side Management	881	55	-	(80)	(25)	**856**
Debt Management	449	267	-	(7)	260	**709**
First Nations Provisions & Costs	486	10	1	(25)	(14)	**472**
Non-Current Pension Costs	114	(66)	-	(48)	(114)	**-**
Site C	523	2	12	-	14	**537**
CIA Amortization	73	(4)	-	-	(4)	**69**
Environmental Provisions & Costs	294	15	(1)	(43)	(29)	**265**
Smart Metering & Infrastructure	173	-	4	(20)	(16)	**157**
IFRS Pension	421	-	-	(29)	(29)	**392**
IFRS Property, Plant & Equipment	1,070	-	-	(23)	(23)	**1,047**
Real Property Sales	46	(15)	1	-	(14)	**32**
Total Finance Charges	-	4	-	13	17	**17**
Other Regulatory Accounts	70	94	2	(7)	89	**159**
Total Regulatory Assets	4,775	297	22	(269)	50	**4,825**
Regulatory Liabilities						
Non-Heritage Deferral	153	(4)	3	-	(1)	**152**
Trade Income Deferral	227	276	9	-	285	**512**
Non-Current Pensions Costs	-	23	-	38	61	**61**
Total Finance Charges	61	(18)	-	(43)	(61)	**-**
Other Regulatory Accounts	57	33	1	(19)	15	**72**
Total Regulatory Liabilities	498	310	13	(24)	299	**797**
Net Regulatory Asset	$ 4,277	$ (13)	$ 9	$ (245)	$ (249)	**$ 4,028**

[1] As permitted by the BCUC, interest charges were accrued to certain regulatory balances at a rate of 3.1 per cent for the nine months ended December 31, 2021 (2020 – 3.5 per cent) at the Company's weighted average cost of debt.
[2] Net Change is comprised of a net decrease to net income of $91 million (2020 – $5 million net increase to net income) and a net decrease to other comprehensive income of $158 million (2020 – $502 million net decrease to other comprehensive loss).

There were no significant changes to the remaining recovery/reversal periods of the regulatory accounts for the nine months ended December 31, 2021. For a summary of the remaining recovery/reversal periods of the regulatory accounts, please refer to Note 15 – Rate Regulation in the Company's 2020/21 Annual Service Plan Report.

Note 10: Other Non-Current Assets

(in millions)	***As at December 31*** **2021**	*As at March 31* 2021
Non-current receivables	**$ 124**	$ 138
Sinking funds	**211**	203
Non-current Site C prepaid expenses	**204**	253
Other	**11**	11
	$ 550	$ 605

Included in the non-current receivables balance are $114 million of receivables (March 31, 2021 - $122 million) attributable to other contributions receivable from a vendor to aid in the construction of a transmission system.

Note 11: Long-Term Debt and Debt Management

The Company's 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 $5.50 billion – this includes a $1.00 billion increase to the limit during the three month period ended December 31, 2021. At December 31, 2021, the outstanding amount under the borrowing program was $3.28 billion (March 31, 2021 - $2.80 billion) and it is included in revolving borrowings.

For the three months ended December 31, 2021, the Company did not issue any bonds (2020 - $nil). For the nine months ended December 31, 2021, the Company issued bonds for net proceeds of $1.57 billion (2020 - $2.50 billion) and a par value of $1.58 billion (2020 - $2.20 billion), a weighted average effective interest rate of 2.4 per cent (2020 - 1.6 per cent) and a weighted average term to maturity of 21.6 years (2020 - 18.1 years).

For the three months ended December 31, 2021, there were no bond maturities (2020 – $500 million). For the nine months ended December 31, 2021, the Company redeemed bonds with a par value of $526 million (2020 - $1.10 billion).

Note 12: 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 nine months ended December 31, 2021, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2021, and March 31, 2021 was as follows:

(in millions)	***As at December 31*** **2021**	*As at March 31* 2021
Total debt, net of sinking funds	**$ 26,265**	$ 24,777
Less: Cash and cash equivalents	**(147)**	(37)
Net Debt	**$ 26,118**	$ 24,740
Retained earnings	**$ 6,632**	$ 6,326
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(14)**	(19)
Total Equity	**$ 6,678**	$ 6,367
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Dividend Payment to the Province

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

As a result, there was no payment to the Province for the year ended March 31, 2021 and no payment is expected for the year ending March 31, 2022.

Note 13: Post-Employment Benefits

The expense recognized for the Company's defined benefit plans prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions for the three and nine months ended December 31, 2021 was $51 million and $152 million, respectively (2020 - $47 million and $140 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2021 were $13 million and $39 million, respectively (2020 - $12 million and $37 million, respectively).

The plan remeasurements used a discount rate of 3.30 per cent as at December 31, 2021 (December 31, 2020 – 2.67 per cent) and a rate of return on plan assets of 10.07 per cent as at December 31, 2021 (December 31, 2020 - 17.35 per cent).

Note 14: Financial Instruments

Categories of Financial Instruments

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at December 31, 2021, and March 31, 2021:

(in millions)	**December 31, 2021** Carrying Value	**December 31, 2021** Fair Value	March 31, 2021 Carrying Value	March 31, 2021 Fair Value
Fair Value Through Profit or Loss (FVTPL):				
Cash equivalents - short-term investments	**$ 94**	**$ 94**	$ 34	$ 34
Amortized Cost:				
Cash	**53**	**53**	3	3
Restricted cash	**87**	**87**	6	6
Accounts receivable and accrued revenue	**862**	**862**	827	827
Non-current receivables	**124**	**138**	138	153
Sinking funds	**211**	**233**	203	233
Accounts payable and accrued liabilities	**(1,384)**	**(1,384)**	(1,589)	(1,589)
Revolving borrowings	**(3,279)**	**(3,279)**	(2,803)	(2,803)
Long-term debt (including current portion due in one year)	**(23,197)**	**(26,199)**	(22,177)	(24,548)
First Nations liabilities (non-current portion)	**(400)**	**(1,124)**	(404)	(741)
Lease liabilities (non-current portion)	**(1,303)**	**(1,303)**	(1,352)	(1,352)
Other liabilities	**(420)**	**(426)**	(424)	(436)

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

The following foreign currency contracts under hedge accounting were in place at December 31, 2021 in a net asset position of $nil (March 31, 2021 – net asset $16 million). Such contracts are used to hedge the principal on US$ 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.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2021

($ amounts in millions)	**December 31, 2021**	March 31, 2021
Cross- Currency Hedging Swaps		
EURO € to CAD$ - notional amount[1]	**€ 402**	€ 402
EURO € to CAD$ - weighted average contract rate	**1.47**	1.47
Weighted remaining term	**6 years**	7 years
Foreign Currency Hedging Forwards		
US$ to CAD$ - notional amount[1]	**US$ 573**	US$ 573
US$ to CAD$ - weighted average contract rate	**1.25**	1.25
Weighted remaining term	**8 years**	9 years

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

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

(in millions)	**December 31, 2021 Fair Value**	March 31, 2021 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)	**$ 20**	$ 16
Foreign currency contract liabilities (cash flow hedges for US$ denominated long-term debt)	**(4)**	(6)
Foreign currency contract assets (cash flow hedges for EURO€ denominated long-term debt)	**-**	11
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)	**(16)**	(5)
	-	16
Non-Designated Derivative Instruments:		
Interest rate contract assets	**4**	-
Interest rate contract liabilities	**(245)**	(125)
Foreign currency contract assets (liabilities)	**19**	(36)
Commodity derivative assets	**185**	88
Commodity derivative liabilities	**(194)**	(139)
	(231)	(212)
Net liability	**$ (231)**	$ (196)

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:

(in millions)	**December 31, 2021**	March 31, 2021
Current portion of derivative financial instrument assets	**$ 155**	$ 87
Current portion of derivative financial instrument liabilities	**(259)**	(235)
Derivative financial instrument assets, non-current	**79**	30
Derivative financial instrument liabilities, non-current	**(206)**	(78)
Net liability	**$ (231)**	$ (196)

Designated cash flow hedges for the three and nine months ended December 31, 2021 had losses of $18 million and $16 million, respectively (2020 – losses of $31 million and $55 million, respectively). The effective portion was recognized in other comprehensive income and the ineffective portion was recognized in finance charges. For the three and nine months ended December 31, 2021, $14 million and $9 million, respectively (2020 - $36 million and $75 million, respectively) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains, respectively (2020 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $3.73 billion (March 31, 2021 – $3.23 billion), used to economically hedge the interest rates on future debt issuances, there was a $169 million decrease and a $190 million decrease, respectively (2020 - $106 million increase and $90 million increase, respectively) in the fair value of these contracts for the three and nine months ended December 31, 2021. For interest rate contracts associated with debt issued, there was a $nil and $77 million decrease, respectively (2020 - $nil and $55 million decrease, respectively) in the fair value of contracts that settled during the three and nine months ended December 31, 2021. The net decrease for the nine months ended December 31, 2021 of $267 million (2020 - $35 million increase) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a net asset balance of $709 million as at December 31, 2021.

Foreign currency contracts for cash management purposes not designated as hedges, for the three and nine months ended December 31, 2021, had a gain of $nil and $2 million, respectively (2020 – loss of $1 million and $2 million, respectively) recognized in finance charges. Foreign currency contracts associated with US$ revolving borrowings not designated as hedges, for the three and nine months ended December 31, 2021, had losses of $6 million and gains $24 million, respectively (2020 – losses of $79 million and $149 million, respectively) recognized in finance charges. These economic hedges offset $7 million of foreign exchange revaluation gains and $23 million of foreign exchange revaluation losses, respectively (2020 – $80 million and $151 million of foreign exchange revaluation gains, respectively) recorded in finance charges with respect to US$ revolving borrowings for the three and nine months ended December 31, 2021.

For commodity derivatives not designated as hedges, net gains of $214 million and $547 million, respectively (2020 – net gains of $178 million and $412 million, respectively) was recorded in trade revenue for the three and nine months ended December 31, 2021.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)	For the three months ended December 31 **2021**	2020	For the nine months ended December 31 **2021**	2020
Deferred inception gains, beginning of the period	**$ 7**	$ 5	**$ 40**	$ 7
New transactions	**(4)**	34	**20**	43
Amortization	**(12)**	(4)	**(69)**	(15)
Foreign currency translation loss	**-**	(1)	**-**	(1)
Deferred inception gains (losses), end of the period	**$ (9)**	$ 34	**$ (9)**	$ 34

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 not recognized in income immediately, but is deferred and amortized into income over the full term of the underlying financial instrument.

Credit Risk

As a result of the COVID-19 pandemic and material disruptions to businesses and the economy, the Company is exposed to credit risk due to customers not being able to pay their electricity bills when due.

Domestic Electricity Receivables

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

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

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

(in millions)	**December 31, 2021**	March 31, 2021
Current	**$ 368**	$ 440
Past due (30-59 days)	**24**	22
Past due (60-89 days)	**5**	6
Past due (More than 90 days)	**5**	7
	402	475
Less: Allowance for doubtful accounts	**(6)**	(6)
	$ 396	$ 469

At the end of each period, a review of the provision for doubtful accounts is performed. It is an assessment of the expected lifetime credit losses of 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 December 31, 2021 there was uncertainty and judgment regarding the impact of COVID-19 on credit risk and expected lifetime credit losses.

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 December 31, 2021 and March 31, 2021:

As at December 31, 2021 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 94	$ -	$ -	$ 94
Derivatives designated as hedges	-	20	-	20
Derivatives not designated as hedges	110	61	43	214
	$ 204	$ 81	$ 43	$ 328

As at December 31, 2021 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (20)	$ -	$ (20)
Derivatives not designated as hedges	(113)	(299)	(33)	(445)
	$ (113)	$ (319)	$ (33)	$ (465)

As at March 31, 2021 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 34	$ -	$ -	$ 34
Derivatives designated as hedges	-	27	-	27
Derivatives not designated as hedges	59	10	21	90
	$ 93	$ 37	$ 21	$ 151

As at March 31, 2021*(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (11)	$ -	$ (11)
Derivatives not designated as hedges	(39)	(173)	(90)	(302)
	$ (39)	$ (184)	$ (90)	$ (313)

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the period, commodity derivatives with a carrying amount of $2 million were transferred from Level 2 to Level 1 (2020 – $nil).

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 nine months ended December 31, 2021 and 2020:

(in millions)		
Balance as at April 1, 2021	**$**	**(69)**
Net gains recognized		106
New transactions		(4)
Existing transactions settled		(23)
Balance as at December 31, 2021	**$**	**10**

(in millions)		
Balance as at April 1, 2020	**$**	**(12)**
Net gains recognized		25
New transactions		(15)
Existing transactions settled		4
Balance as at December 31, 2020	**$**	**2**

There were no transfers between Level 3 and 2 during the period (2020 – no transfers).

During the three and nine months ended December 31, 2021, unrealized gains of $18 million and $70 million, respectively (2020 - $18 million and $33 million unrealized gains, respectively) were recognized on Level 3 derivative commodity instruments still on hand. These gains were recognized in trade revenues.

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

The key unobservable inputs in the valuation of certain Level 3 financial instruments includes components of forward commodity prices and delivery or receipt volumes. A sensitivity analysis was prepared using the Company's assessment of a reasonably possible change in various components of forward prices and volumes of 10 percent. Forward commodity prices used in determining Level 3 base fair value at December 31, 2021 range between $0.20-$414 per MWh and a 10 percent increase/decrease in certain components of these prices would decrease/increase fair value by $44 million. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $7 million.

Note 15: Other Non-Current Liabilities

(in millions)	***As at December 31*** **2021**	*As at March 31* 2021
Provisions		
Environmental liabilities	**$ 307**	$ 326
Decommissioning obligations	**87**	87
Other	**58**	63
	452	476
First Nations liabilities	**414**	418
Other contributions	**227**	230
Other liabilities	**420**	424
	1,513	1,548
Less: Current portion, included in accounts payable and accrued liabilities	**(141)**	(146)
	$ 1,372	$ 1,402

Note 16: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

(in millions)	*For the nine months ended December 31* **2021**	2020
Restricted Cash	**$ (82)**	$ 6
Accounts receivable and accrued revenue	**(21)**	15
Inventories	**(81)**	(38)
Prepaid expenses	**91**	72
Other non-current assets	**54**	4
Accounts payable and accrued liabilities	**(165)**	(368)
Unearned revenues and contributions in aid	**120**	135
Post-employment benefits	**(4)**	(3)
Other non-current liabilities	**(22)**	59
	$ (110)	$ (118)

Non-Cash Investing Transactions:

(in millions)	*For the nine months ended December 31* **2021**	2020
Contributions in kind received for property, plant and equipment	**$ 37**	$ 42

Note 17: Seasonality of Operating Results

Due to the seasonal nature of the Company's operations, the condensed consolidated interim statement of comprehensive income is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on the Company's operating results.