British Columbia Hydro and Power Authority

2025/26

SECOND QUARTER REPORT

FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2025

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 six months ended September 30, 2025 and should be read in conjunction with the 2024/25 Annual Service Plan Report and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three and six months ended September 30, 2025.

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

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

Highlights

- Net income for the three months ended September 30, 2025 was $45 million, $24 million lower than the same period in the prior fiscal year. Net loss for the six months ended September 30, 2025 was $8 million, $122 million lower than the net income of $114 million in the same period in the prior fiscal year. The decrease in net income in both periods was driven by lower net movement in regulatory account balances (i.e., lower deferred amounts which result in lower net income) and higher operating expenses, partially offset by higher revenues and lower finance charges. Typically, BC Hydro's net income is low or in a loss position in the first half of the fiscal year due to the seasonality of BC Hydro's domestic revenues where higher revenue is typically expected in the fall and winter, compared to costs which are generally more constant throughout the year.

- Total revenues for the three and six months ended September 30, 2025 were $1.94 billion and $3.49 billion, respectively, $123 million and $127 million higher than the same periods in the prior fiscal year. The increase in revenues for the three months ended September 30, 2025 was due to higher domestic revenues and higher trade revenues. The increase in revenues for the six months ended September 30, 2025 was primarily due to higher domestic revenues. Domestic revenues were higher in both periods due to a combination of average customer rate increases of 3.75 per cent effective April 1, 2025 and a 3 per cent increase in sales volumes, compared to the same periods in the prior fiscal year. Trade revenues were higher for the three months ended September 30, 2025 primarily due to higher average sales prices.

- Energy costs for the three and six months ended September 30, 2025 were $681 million and $1.35 billion, respectively, $69 million (or 9 per cent) and $79 million (or 6 per cent) lower than the same periods in the prior fiscal year. The lower energy costs were primarily due to a decrease in market purchases, mainly driven by lower electricity import costs as a result of lower import volumes compared to the same periods in the prior fiscal year. Net electricity import volumes for the six months ended September 30, 2025 were 2,041 GWh, 2,589 GWh (or 56 percent) lower than the prior fiscal year of 4,630 GWh primarily due to better water conditions. The decrease in costs was partially offset by higher purchases from Independent Power Producers (IPPs) due to a higher volume of purchases compared to the same periods in the prior fiscal year.

- Water inflows (energy equivalent) to the system for the six months ended September 30, 2025 were below the historical average, although higher than the same period in the prior fiscal year. The below average water inflows for the first six months ended September 30, 2025 were primarily driven by the below average snowpack in the spring of 2025. As at September 30, 2025, system energy storage was tracking above the historic average and higher than September 30, 2024.

- Capital expenditure investments, before contributions in aid of construction, for the three and six months ended September 30, 2025 were $983 million and $1.82 billion, a $87 million and $270 million decrease, respectively, compared to the same periods in the prior fiscal year primarily due to lower Site C Project expenditures as major scopes of work were completed in the prior fiscal year. The decrease was partially offset by higher capital expenditures classified as growth of $136 million (or 16 per cent) and $213 million (or 15 per cent), respectively, compared to the same periods in the prior fiscal year for generation, transmission and distribution capital categories, representing investments to expand the electricity system to meet future demand as well as renew our existing infrastructure.

  During the six months ended September 30, 2025, capital expenditure investments transferred to assets in-service were $716 million compared to $10 million in the prior period. This included $304 million of additional eligible costs related to Site C Units 1 to 4 after they were placed in-service in the prior year. The Site C Project placed the remaining two generating units in-service in August 2025, earlier than the approved schedule and $412 million was transferred from Unfinished Construction to Property, Plant and Equipment. The Site C Project is on track to be completed within the approved $16 billion budget.

- The net regulatory asset balance as at September 30, 2025 was $2.40 billion, a $0.12 billion decrease, compared to $2.52 billion as at March 31, 2025.

Consolidated Results of Operations

	For the three months ended September 30			*For the six months ended September 30*		
($ in millions)	**2025**	2024	Change	**2025**	2024	Change
Total Revenues	**$ 1,937**	$ 1,814	$ 123	**$ 3,492**	$ 3,365	$ 127
Operating expenses	**$ 1,635**	$ 1,571	$ 64	**$ 3,217**	$ 3,076	$ 141
Net Income (Loss)	**$ 45**	$ 69	$ (24)	**$ (8)**	$ 114	$ (122)
Capital Expenditure Investments	**$ 983**	$ 1,070	$ (87)	**$ 1,818**	$ 2,088	$ (270)
GWh Sold (Domestic)	**13,713**	13,315	398	**26,483**	25,739	744

($ in millions)	***As at September 30, 2025***	*As at March 31, 2025*	Change
Total Assets and Regulatory Balances	**$ 53,852**	$ 53,178	$ 674
Shareholder's Equity	**$ 8,263**	$ 8,254	$ 9
Net Debt	**$ 33,322**	$ 32,049	$ 1,273
Debt to Equity	**80 : 20**	80 : 20	n/a
Number of Domestic Customer Accounts	**2,278,494**	2,256,615	21,879

Revenues

For the three and six months ended September 30, 2025, total revenues of $1.94 billion and $3.49 billion, respectively, were $123 million (or 7 per cent) and $127 million (or 4 per cent), respectively, higher than the same periods in the prior fiscal year. The increase for the three months ended

September 30, 2025 was primarily due to higher domestic revenues of $63 million and higher trade revenues of $60 million. The increase for the six months ended September 30, 2025 was primarily due to higher domestic revenues of $140 million, partially offset by lower trade revenues of $13 million.

	($ in millions)		(gigawatt hours)	
for the three months ended September 30	**2025**	2024	**2025**	2024
Revenues				
Residential	**$ 486**	$ 479	**3,779**	3,894
Light industrial and commercial	**525**	504	**4,744**	4,716
Large industrial	**246**	235	**3,627**	3,622
Other sales	**214**	190	**1,563**	1,083
Domestic Revenues	**1,471**	1,408	**13,713**	13,315
Trade Revenues[1]	**466**	406	**5,684**	5,725
Revenues	**$ 1,937**	$ 1,814	**19,397**	19,040

	($ in millions)		(gigawatt hours)	
for the six months ended September 30	**2025**	2024	**2025**	2024
Revenues				
Residential	**$ 993**	$ 972	**7,743**	7,853
Light industrial and commercial	**1,030**	988	**9,331**	9,233
Large industrial	**492**	461	**7,256**	7,086
Other sales	**357**	311	**2,153**	1,567
Domestic Revenues	**2,872**	2,732	**26,483**	25,739
Trade Revenues[1]	**620**	633	**10,888**	10,445
Revenues	**$ 3,492**	$ 3,365	**37,371**	36,184

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

Domestic Revenues

Domestic revenues for the three months and six months ended September 30, 2025, were $1.47 billion and $2.87 billion, respectively, $63 million (or 4 per cent) and $140 million (or 5 per cent), respectively, higher compared to the same periods in the prior fiscal year. The increase was primarily due to a 3.75 per cent bill increase approved by the British Columbia Utilities Commission (BCUC) effective April 1, 2025 and higher domestic sales volumes compared to the same periods in the prior fiscal year.

Domestic sales volumes for the three and six months ended September 30, 2025, were 398 GWh (or 3 per cent) and 744 GWh (or 3 per cent) higher than the same periods in the prior fiscal year. Excluding electricity exports (included in Other Sales), sales volumes for the three and six months ended September 30, 2025, were 9 GWh (or less than 1 per cent) lower, and 268 GWh (or 1 per cent) higher than the same periods in the prior fiscal year.

Trade Revenues

Total trade revenues for the three and six months ended September 30, 2025 were $466 million and $620 million, respectively, an increase of $60 million (or 15 per cent) and decrease of $13 million (or 2 per cent), respectively, compared to the same periods in the prior fiscal year. The increase for the three months ended September 30, 2025 was primarily driven by higher average sales prices.

Operating Expenses

For the three months ended September 30, 2025, total operating expenses of $1.64 billion were $64 million (or 4 per cent) higher than the same period in the prior fiscal year. The increase was primarily due to higher amortization and depreciation expenses of $53 million, higher grants, taxes and other costs of $39 million, higher materials and external services costs of $27 million, and higher personnel expenses of $15 million, partially offset by lower energy costs of $69 million.

For the six months ended September 30, 2025, total operating expenses of $3.22 billion were $141 million (or 5 per cent) higher than the same period in the prior fiscal year. The increase was primarily due to higher amortization and depreciation expenses of $110 million, higher grants, taxes and other costs of $41 million, higher materials and external services costs of $41 million, and higher personnel expenses of $33 million, partially offset by lower energy costs of $79 million.

Energy Costs

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

	($ in millions)		*(gigawatt hours)*	
for the three months ended September 30	**2025**	2024	**2025**	2024
Energy Costs				
Purchases from Independent Power Producers	**$ 390**	$ 377	**4,026**	3,847
Market purchases[1]	**125**	205	**6,723**	7,577
Other expenses	**10**	11	**19**	22
Electricity and gas purchases	**525**	593	**10,768**	11,446
Water rental payments (hydro generation)[2]	**80**	70	**9,945**	8,622
Transmission charges	**76**	87	**-**	-
Energy Costs	**$ 681**	$ 750	**20,713**	20,068

	($ in millions)		*(gigawatt hours)*	
for the six months ended September 30	**2025**	2024	**2025**	2024
Energy Costs				
Purchases from Independent Power Producers	**$ 738**	$ 659	**8,144**	7,589
Market purchases[1]	**300**	426	**13,814**	15,606
Other expenses	**21**	22	**47**	52
Electricity and gas purchases	**1,059**	1,107	**22,005**	23,247
Water rental payments (hydro generation)[2]	**161**	142	**17,487**	15,266
Transmission charges	**132**	182	**-**	-
Energy Costs	**$ 1,352**	$ 1,431	**39,492**	38,513

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

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

Energy costs for the three and six months ended September 30, 2025 were $681 million and $1.35 billion, respectively, $69 million (or 9 per cent) and $79 million (or 6 per cent) lower than the same periods in the prior fiscal year.

Electricity and gas purchases for the three and six months ended September 30, 2025 were $525 million and $1.06 billion, respectively, $68 million (or 11 per cent) and $48 million (or 4 per cent) lower than the same periods in the prior fiscal year. The decrease in costs was primarily due to a decrease in market purchases, mainly driven by lower imports of electricity compared to the same periods in the prior fiscal year. Net electricity import volumes for the six months ended September 30, 2025 were 2,041 GWh, 2,589 GWh (or 56 percent) lower than the prior fiscal year of 4,630 GWh primarily due to better water conditions. The decrease in costs was partially offset by higher purchases from Independent Power Producers (IPPs) largely due to higher deliveries to BC Hydro from hydro IPPs in the current year compared to the same periods in the prior fiscal year.

Water rental payments for the three and six months ended September 30, 2025 were $80 million and $161 million, respectively, $10 million (or 14 per cent) and $19 million (or 13 per cent) higher than the same periods in the prior fiscal year. Water rental payments are based on the prior calendar year's hydro generation volumes, and hydro generation volumes were higher in calendar 2024 compared to calendar 2023 due to higher water inflows.

Transmission charges for the three and six months ended September 30, 2025 were $76 million and $132 million, respectively, $11 million (or 13 per cent) and $50 million (or 27 per cent) lower than the same periods in the prior fiscal year primarily due to lower transmission costs related to trading activity.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system for the six months ended September 30, 2025 were below the historical average, although higher than the same period in the prior fiscal year. The below average inflows for the first six months ended September 30, 2025 were primarily driven by the below average snowpack in the spring of 2025. As at September 30, 2025, system energy storage was tracking above the historic average and higher than September 30, 2024. While BC Hydro was a net importer in the quarter, it imported less compared to the same period in the prior fiscal year.

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

Personnel Expenses

Personnel expenses include salaries, wages, and benefits for employees that deliver operational activities and programs, support capital projects and programs, and post-employment benefits. Personnel expenses for the three and six months ended September 30, 2025 were $234 million and $478 million, respectively, $15 million (or 7 per cent) and $33 million (or 7 per cent) higher than the same periods in the prior fiscal year due to additional employees primarily to deliver increased capital project and operational maintenance work.

Materials and External Services

Materials and External Services primarily include materials, supplies, and contractor fees to deliver operational requirements and support capital projects and programs. Materials and external services for the three and six months ended September 30, 2025 were $280 million and $547 million, respectively, $27 million (or 11 per cent) and $41 million (or 8 per cent), respectively, higher than the same periods in the prior fiscal year primarily due to higher technology costs, higher maintenance costs and higher environmental costs, partially offset by a decrease in rebates for electric vehicles provided by BC Hydro.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and depreciation of right-of-use assets. Amortization and depreciation expense for the three months and six months ended September 30, 2025 were $337 million and $669 million, respectively, $53 million (or 19 per cent) and $110 million (or 20 per cent) higher than the same periods in the prior fiscal year. This was primarily due to incremental depreciation of the Site C Project assets, including the dam, powerhouse, and all six generating units, that are in-service which were not yet in-service in the same period in the prior fiscal year.

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

Total grants, taxes and other costs for the three and six months ended September 30, 2025, were $132 million and $226 million, respectively, $39 million (or 42 per cent) and $41 million (or 22 per cent) higher than the same periods in the prior fiscal year primarily due to an increase in environmental provisions related to the remediation of polychlorinated biphenyl (PCB) and an increase in provisions recognized for decommissioning work associated with leased land.

Capitalized Costs

Capitalized costs includes costs directly attributable to capital expenditure investments that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the three and six months ended September 30, 2025 were $29 million and $55 million, respectively, comparable to the $28 million and $50 million, respectively, in the same periods in the prior fiscal year.

Finance Charges

Finance charges for the three months ended September 30, 2025 were $318 million, comparable to the $320 million in the same period in the prior fiscal year.

Finance charges for the six months ended September 30, 2025 were $424 million, a decrease of $64 million (or 13 per cent) compared to the same period in the prior fiscal year. The decrease was primarily due to gains on interest rate hedges used to economically hedge the interest rates on future debt issuances in the current period as compared to losses in the same period in the prior fiscal year. The decrease was partially offset by lower capitalization of interest mainly due to Site C as a large portion of its assets are now in-service.

Regulatory Transfers

In accordance with 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 differences between forecast and actual costs or revenues to future periods. Deferred amounts are included in customer rates in future periods, subject to approval by the BCUC, and have the effect of adjusting net income.

Net regulatory account transfers are comprised of the following:

(in millions)	*As at April 1 2025*	*Addition (Reduction) / Transfers*	*Interest*	*Amortization*	*Net Change*	***As at September 30 2025***
Total Regulatory Assets	$ 5,930	$ 215	$ 47	$ (832)	$ (570)	**$ 5,360**
Total Regulatory Liabilities	3,410	394	38	(877)	(445)	**2,965**
Net Regulatory Asset	$ 2,520	$ (179)	$ 9	$ 45	$ (125)	**$ 2,395**

For the six months ended September 30, 2025, there was a net decrease of $125 million (or 5%) to the Company's regulatory accounts compared to a net increase of $423 million in the same period in the prior fiscal year. The net regulatory asset balance as at September 30, 2025 was $2.40 billion compared to $2.52 billion as at March 31, 2025.

Significant changes to the regulatory accounts during the six months ended September 30, 2025 included a $237 million net reduction to the Non-Current Pension Costs Account primarily due to higher assets returns and an increase in discount rates, a $142 million reduction to the Debt Management Account primarily due to a net increase in the fair value of interest rate hedges resulting from an increase in forward interest rates, partially offset by a $110 million addition to the Cost of Energy Variance Accounts primarily due to net electricity imports as compared to planned net electricity exports, and a $82 million addition to the Demand-Side Management Account for expenditures during the period.

BC Hydro has BCUC approved regulatory mechanisms to collect 40 of 42 regulatory accounts with balances at September 30, 2025 in rates over various periods. For the remaining 2 regulatory accounts, BC Hydro will apply for a recovery mechanism at a future date when a recovery mechanism is required.

Liquidity and Capital Resources

Cash flow provided by operating activities for the six months ended September 30, 2025 was $418 million, compared to $312 million provided by operating activities in the same period in the prior fiscal year. The increase was primarily due to higher cash from changes in working capital.

Net debt as at September 30, 2025 was $33.32 billion compared to $32.05 billion as at March 31, 2025. The increase was mainly a result of issuances of long-term bonds for net proceeds of $2.02 billion (net of redemptions) primarily to fund capital expenditure investments and to manage working capital. This is partially offset by a decrease in revolving borrowings of $724 million.

As at September 30, 2025, the Company has a working capital deficit of $4.59 billion which is primarily due to its revolving borrowing program. The working capital deficit is considered to be in the normal course of business where the Company has access to revolving credit facilities and debt issuances through the Province to manage cash flow requirements and does not impact operations.

Capital Expenditure Investments

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

	For the three months ended September 30		*For the six months ended September 30*	
($ in millions)	**2025**	2024	**2025**	2024
Transmission lines and substation replacements and expansion	**$ 300**	$ 210	**$ 542**	$ 410
Generation replacements and expansion	**194**	142	**331**	267
Distribution system improvements and expansion	**226**	243	**439**	456
General, including technology, vehicles and buildings	**99**	85	**193**	161
Site C Project	**164**	390	**313**	794
Capital Expenditure Investments	**$ 983**	$ 1,070	**$ 1,818**	$ 2,088

The decrease in capital expenditure investments of $87 million and $270 million, respectively, for the three and six months ended September 30, 2025 compared to the same periods in the prior fiscal year was primarily due to Site C Project expenditures as major scopes of work were completed in the prior fiscal year, resulting in less construction costs for the current year. The decrease in Site C Project capital expenditure investments was partially offset by increases in transmission, generation and general capital expenditure categories. Annual capital expenditure investments can vary depending on the timing and scope of projects.

Transmission lines and substation replacements and expansion included capital expenditure investments on transmission overhead lines, cables, substations, telecommunication systems, and transmission power equipment. Key capital expenditure investments included the following projects/programs: Treaty Creek Terminal – Transmission Load Interconnection (KSM), Campbell Heights Property Purchase, 2L333 – Load interconnection – Enbridge APP CS16, Peace to Kelly Lake Stations Sustainment, Mainwaring Station Upgrade, and North Coast Transmission.

Generation replacements and expansion included capital expenditure investments on dam safety projects as well as on generating facilities and related major equipment such as turbines, generators, governors, exciters, transformers, and circuit breakers. Key capital expenditure investments included the following projects: John Hart Dam Seismic Upgrade, Ladore Spillway Seismic Upgrade, Ruskin – Left Abutment Slope Sinkhole Remediation, W.A.C. Bennett Dam Seal Low Level Outlets, and Anahim Lake – Station Upgrades for Renewable Energy Integration.

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

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

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

Rate Regulation

BC Hydro is regulated by the BCUC who is authorized to set BC Hydro's rates.

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

Risk Management

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

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

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

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue, cost of energy and finance charges. These are influenced by several elements, which generally fall into the following six categories: hydro generation, customer demand, electricity imports/exports, trade income, deliveries from electricity purchase agreements, and interest rates.

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

In addition to the six factors identified above, the ongoing uncertainty surrounding United States tariff and trade policies including retaliatory measures by Canada and British Columbia is being carefully monitored to determine potential financial impacts to BC Hydro.

As of September 30, 2025, the Site C Project forecast remains within the $16 billion approved July 2021 budget with all 6 generating units now in-service. BC Hydro is now focused on completing the remaining project scope and closing the project. The BC Hydro Board of Directors and the project will continue to manage potential risks including commercial negotiations and claims with contractors.

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 2024/25 Annual Service Plan Report for the year ended March 31, 2025. In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives is outlined at 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 March 2025 forecast net income for 2025/26 and budget for 2026/27 at $712 million which is consistent with the amount required by Order in Council No. 485. In addition, net income budget for 2027/28 is $712 million.

The Company's financial performance can fluctuate significantly due to the factors discussed in the preceding section, many of which are non-controllable. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The Service Plan for 2025/26 assumed average water inflows (100 per cent of average) based on a hydrology forecast before the 2024/25 snowpack measurement data was available, domestic sales of 57,001 GWh, average market energy prices of US $65.23/MWh, short-term interest rates of 2.68 per cent, and a Canadian to US dollar exchange rate of US $0.7453.

The U.S. government's announcement earlier this year regarding new tariffs on Canadian imports has prompted retaliatory measures from Canada and British Columbia. BC Hydro continues to take actions to limit procurement from U.S. suppliers where viable to comply with provincial regulation enacted under the Economic Stabilization Tariff Response Act. BC Hydro purchases the vast majority of goods and services from Canadian suppliers, but continues advancing longer-term plans to diversify its supply chain and reduce reliance on U.S. suppliers, including for certain critical goods that are typically sourced from the U.S. and have no readily available alternatives. With respect to cost impacts from tariffs, these have remained relatively low. However, tariffs continue to represent risks of cost escalation and contribute to uncertainty in cost projections and planning.

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

Uncertainty around water inflows could have an adverse impact on BC Hydro's future performance. As at September 30, 2025, the forecast water inflows for this fiscal year are expected to be below the historical average, and higher than the actual water inflows in the two prior fiscal years. Snowpack levels were below the historical average and the residual water supply will be influenced by precipitation over the remainder of the fiscal year. Cost of energy may be higher due to imports in times of deficit and domestic revenues may be higher due to exports in times of surplus. Variability in seasonal and annual surplus or deficit amounts affects BC Hydro's cost of energy, domestic revenues, and financial performance.

Unaudited Condensed Consolidated Interim Statements of Comprehensive Income

(in millions)	*For the three months ended September 30* **2025**	2024	*For the six months ended September 30* **2025**	2024
Revenues (Note 3)				
Domestic	**$ 1,471**	$ 1,408	**$ 2,872**	$ 2,732
Trade	**466**	406	**620**	633
Revenues	**1,937**	1,814	**3,492**	3,365
Expenses				
Operating expenses (Note 4)	**1,635**	1,571	**3,217**	3,076
Finance charges (Note 5)	**318**	320	**424**	488
Net Loss Before Movement in Regulatory Balances	**(16)**	(77)	**(149)**	(199)
Net movement in regulatory balances (Note 9)	**61**	146	**141**	313
Net Income (Loss)	**45**	69	**(8)**	114
Other Comprehensive Income				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges	**26**	8	**25**	10
Reclassification to income of derivatives designated as cash flow hedges	**(30)**	(7)	**(4)**	(17)
Foreign currency translation gain (loss)	**22**	(3)	**(24)**	2
Items That Will Not Be Reclassified Subsequently to Net Income				
Actuarial gain (loss)	**154**	(200)	**286**	(113)
Other Comprehensive Income (Loss) before movement in regulatory balances	**172**	(202)	**283**	(118)
Net movements in regulatory balances (Note 9)	**(169)**	204	**(266)**	110
Other Comprehensive Income (Loss)	**3**	2	**17**	(8)
Total Comprehensive Income	**$ 48**	$ 71	**$ 9**	$ 106

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

Unaudited Condensed Consolidated Interim Statements of Financial Position

(in millions)	*As at September 30* **2025**	*As at March 31* 2025
Assets		
Current Assets		
Cash and cash equivalents	$ **153**	$ 136
Restricted cash	**-**	35
Accounts receivable and accrued revenue	**836**	820
Inventories (Note 7)	**480**	452
Prepaid expenses	**292**	230
Current portion of sinking funds	**220**	225
Current portion of derivative financial instrument assets (Note 14)	**247**	260
	2,228	2,158
Non-Current Assets		
Property, plant and equipment (Note 8)	**44,107**	42,945
Right-of-use assets	**1,154**	1,180
Intangible assets (Note 8)	**659**	651
Derivative financial instrument assets (Note 14)	**114**	106
Sinking funds	**55**	54
Other non-current assets (Note 10)	**175**	154
	46,264	45,090
Total Assets	**48,492**	47,248
Regulatory Balances (Note 9)	**5,360**	5,930
Total Assets and Regulatory Balances	$ **53,852**	$ 53,178
Liabilities and Equities		
Current Liabilities		
Accounts payable and accrued liabilities	$ **2,059**	$ 2,027
Current portion of long-term debt and revolving borrowings (Note 11)	**4,506**	5,284
Current portion of unearned revenues and contributions in aid	**130**	123
Current portion of derivative financial instrument liabilities (Note 14)	**122**	158
	6,817	7,592
Non-Current Liabilities		
Long-term debt (Note 11)	**29,244**	27,180
Lease liabilities	**1,240**	1,270
Derivative financial instrument liabilities (Note 14)	**60**	118
Unearned revenues and contributions in aid	**3,204**	3,069
Post-employment benefits (Note 13)	**622**	862
Other non-current liabilities (Note 15)	**1,437**	1,423
	35,807	33,922
Total Liabilities	**42,624**	41,514
Regulatory Balances (Note 9)	**2,965**	3,410
Total Liabilities and Regulatory Balances	**45,589**	44,924
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**8,253**	8,261
Accumulated other comprehensive loss	**(50)**	(67)
	8,263	8,254
Total Liabilities, Regulatory Balances, and Shareholder's Equity	$ **53,852**	$ 53,178

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 Loss on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2024	$ 10	$ (51)	$ (41)	$ 60	$ 7,677	$ 7,696
Distribution to the Province	-	-	-	-	(2)	(2)
Comprehensive Income (Loss)	(1)	(7)	(8)	-	114	106
Balance as at September 30, 2024	$ 9	$ (58)	$ (49)	$ 60	$ 7,789	$ 7,800
Balance as at April 1, 2025	$ 18	$ (85)	$ (67)	$ 60	$ 8,261	$ 8,254
Comprehensive Income (Loss)	(4)	21	17	-	(8)	9
Balance as at September 30, 2025	$ 14	$ (64)	$ (50)	$ 60	$ 8,253	$ 8,263

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

Unaudited Condensed Consolidated Interim Statements of Cash Flows

For the six months ended September 30 (in millions)	**2025**	2024
Operating Activities		
Net income	**$ (8)**	$ 114
Regulatory account transfers (Note 9)	**(141)**	(313)
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 6)	**669**	559
Unrealized losses (gains) on derivative financial instruments	**(159)**	27
Post-employment benefit plan expenses	**41**	37
Interest expenses accrual	**600**	550
Other items	**(6)**	8
	996	982
Changes in working capital and other assets and liabilities (Note 16)	**10**	(101)
Interest paid	**(588)**	(569)
Cash provided by operating activities	**418**	312
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,736)**	(1,754)
Cash used in investing activities	**(1,736)**	(1,754)
Financing Activities		
Long-term debt issued (Note 11)	**2,923**	3,570
Long-term debt retired (Note 11)	**(900)**	(10)
Receipt of revolving borrowings	**4,027**	4,286
Repayment of revolving borrowings	**(4,722)**	(6,391)
Payment of principal portion of lease liability	**(48)**	(36)
Settlement of hedging derivatives	**75**	107
Other items	**(15)**	(16)
Cash provided by financing activities	**1,340**	1,510
Increase (Decrease) in cash and cash equivalents	**22**	68
Effect of exchange rate fluctuations on cash held	**(5)**	-
Cash and cash equivalents, beginning of year	**136**	96
Cash and cash equivalents, end of year	**$ 153**	$ 164

See Note 16 for cash flow supplement

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

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2025

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 wholly-owned operating subsidiaries including 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 the principles of IAS 34, *Interim Financial Reporting,* and except as described below, were prepared using the same accounting policies as described in BC Hydro's 2024/25 Annual Service Plan Report.

These interim financial statements should be read in conjunction with the BC Hydro's 2024/25 Annual Service Plan Report.

These interim financial statements were approved on behalf of the Board of Directors on November 18, 2025.

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.

	For the three months ended September 30		*For the six months ended September 30*	
(in millions)	**2025**	2024	**2025**	2024
Domestic				
Residential	**$ 486**	$ 479	**$ 993**	$ 972
Light industrial and commercial	**525**	504	**1,030**	988
Large industrial	**246**	235	**492**	461
Other sales	**214**	190	**357**	311
Total Domestic	**1,471**	1,408	**2,872**	2,732
Total Trade[1]	**466**	406	**620**	633
Total Revenue	**$ 1,937**	$ 1,814	**$ 3,492**	$ 3,365

[1] Includes revenues of $371 million and $348 million recognized under IFRS 9, *Financial Instrument* s for the three and six months ended September 30, 2025, respectively (2024 - $184 million and $195 million, respectively) and revenue of $4 million and reduction in revenue of $6 million, respectively recognized under IAS 2, Inventories (2024 - $2 million and $3 million, respectively revenue recognized).

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2025

Note 4: Operating Expenses

	For the three months ended September 30		For the six months ended September 30	
(in millions)	**2025**	2024	**2025**	2024
Electricity and gas purchases	**$ 525**	$ 593	**$ 1,059**	$ 1,107
Water rentals	**80**	70	**161**	142
Transmission charges	**76**	87	**132**	182
Personnel expenses	**234**	219	**478**	445
Materials and external services	**280**	253	**547**	506
Amortization and depreciation (Note 6)	**337**	284	**669**	559
Grants, taxes and other costs	**132**	93	**226**	185
Capitalized costs	**(29)**	(28)	**(55)**	(50)
	$ 1,635	$ 1,571	**$ 3,217**	$ 3,076

Note 5: Finance Charges

	For the three months ended September 30		For the six months ended September 30	
(in millions)	**2025**	2024	**2025**	2024
Interest on long-term debt	**$ 295**	$ 279	**$ 577**	$ 550
Interest on lease liabilities	**11**	12	**22**	23
Interest on defined benefit plan obligations	**10**	8	**20**	17
Losses (Gains) on derivative financial instruments	**4**	150	**(144)**	139
Capitalized interest	**(29)**	(139)	**(60)**	(272)
Other	**27**	10	**9**	31
	$ 318	$ 320	**$ 424**	$ 488

Note 6: Amortization and Depreciation

	For the three months ended September 30		For the six months ended September 30	
(in millions)	**2025**	2024	**2025**	2024
Depreciation of property, plant and equipment	**$ 293**	$ 241	**$ 581**	$ 475
Depreciation of right-of-use assets	**23**	22	**47**	43
Amortization of intangible assets	**21**	21	**41**	41
	$ 337	$ 284	**$ 669**	$ 559

Note 7: Inventories

(in millions)	***As at September 30*** **2025**	*As at March 31* 2025
Materials and Supplies and Environmental Products	**$ 308**	$ 301
Natural Gas and Certain Carbon Products	**172**	151
	$ 480	$ 452

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 six months ended September 30, 2025 were $983 million and $1.82 billion, respectively (2024 - $1.07 billion and $2.09 billion, respectively).

As of September 30, 2025, the Company had contractual commitments to spend $1.51 billion on major property, plant and equipment projects (for individual projects greater than $20 million).

Note 9: Rate Regulation

Regulatory Accounts

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

(in millions)	*For the three months ended September 30* **2025**	2024	*For the six months ended September 30* **2025**	2024
Net increase in regulatory balances related to net income	**$ 61**	$ 146	**$ 141**	$ 313
Net increase (decrease) in regulatory balances related to OCI	**(169)**	204	**(266)**	110
	$ (108)	$ 350	**$ (125)**	$ 423

The amount reflected in the Net Change column in the following table represents the impact on comprehensive income for the applicable period. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

(in millions)	*As at April 1 2025*	*Addition (Reduction)/ Transfers*	*Interest* [1]	*Amortization*	*Net Change*	***As at September 30 2025***
Total Regulatory Assets	$ 5,930	$ 215	$ 47	$ (832)	$ (570)	**$ 5,360**
Total Regulatory Liabilities	3,410	394	38	(877)	(445)	**2,965**
Net Regulatory Asset	$ 2,520	$ (179)	$ 9	$ 45	$ (125)	**$ 2,395**

[1]As permitted by the BCUC, interest charges were accrued to certain regulatory balances at the Company's weighed average cost of debt of 3.5 per cent per annum for the six months ended September 30, 2025 (2024 – 3.7 per cent).

There were no significant changes to the remaining recovery/reversal periods for the six months ended September 30, 2025. Refer to Note 16 – Rate Regulation in the Company's 2024/25 Annual Service Plan Report.

Note 10: Other Non-Current Assets

(in millions)	***As at September 30* 2025**	*As at March 31* 2025
Non-current receivables	**$ 96**	$ 114
Other	**79**	40
	$ 175	$ 154

Included in the non-current receivables balance are $87 million of receivables (March 31, 2025 - $98 million) from a vendor to aid in the construction of a transmission system.

Note 11: Long-Term Debt, Revolving Borrowings 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. At September 30, 2025, the outstanding amount under the borrowing program was $2.53 billion (March 31, 2025 - $3.25 billion). This $2.53 billion is included in the current portion of long-term debt and revolving borrowings in the Statements of Financial Position.

For the three months ended September 30, 2025, the Company issued bonds for net proceeds of $1.05 billion (2024 - $1.67 billion) and a par value of $1.08 billion (2024 - $1.61 billion), a weighted average effective interest rate of 4.4 per cent (2024 - 4.0 per cent) and a weighted average term to maturity of 23.6 years (2024 - 25.4 years). For the six months ended September 30, 2025, the Company issued bonds for net proceeds of $2.92 billion (2024 - $3.57 billion) and a par value of $2.98 billion (2024 - $3.56 billion), a weighted average effective interest rate of 4.4 per cent (2024 - 4.2 per cent) and a weighted average term to maturity of 25.1 years (2024 - 24.5 years).

For the three months ended September 30, 2025, there were no bond maturities (2024 – $10 million). For the six months ended September 30, 2025, the Company redeemed bonds at maturity with a par value of $900 million (2024 – $10 million).

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 six months ended September 30, 2025, there were no changes in the approach to capital management.

The debt to equity ratio at September 30, 2025, and March 31, 2025 was as follows:

(in millions)	***As at September 30*** **2025**	*As at March 31* 2025
Total debt	**$ 33,750**	$ 32,464
Less: Sinking funds	**(275)**	(279)
Less: Cash and cash equivalents	**(153)**	(136)
Net Debt	**$ 33,322**	$ 32,049
Retained earnings	**$ 8,253**	$ 8,261
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(50)**	(67)
Total Equity	**$ 8,263**	$ 8,254
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, the payment to the Province will remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

As BC Hydro did not achieve a debt to equity ratio of 60:40 there was no payment for the year ended March 31, 2025. For the same reason, BC Hydro does not expect to make a payment for the year ending March 31, 2026.

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 six months ended September 30, 2025 was $44 million and $88 million, respectively (2024 - $38 million and $76 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and six months ended September 30, 2025 were estimated to be $17 million and $34 million, respectively (2024 - $15 million and $31 million, respectively).

The plan remeasurements used a discount rate of 4.81 per cent per annum as at September 30, 2025 (September 30, 2024 - 4.68 per cent), and a rate of return on plan assets of positive 6.63 per cent as at September 30, 2025 (September 30, 2024 - positive 5.89 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 September 30, 2025, and March 31, 2025. It does not include fair value information for non-derivative financial instruments not measured at fair value if the carrying amount is a reasonable approximation of fair value which include cash and cash equivalents, restricted cash, accounts receivable and accrued revenue, accounts payable, accrued liabilities and revolving borrowings. Their carrying amount is a reasonable approximation of fair value due to the short duration of these financial instruments. When the carrying value differs from fair value, the fair values of non-derivative financial instruments would be classified as Level 2 of the fair value hierarchy.

	September 30, 2025		March 31, 2025	
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Amortized Cost:				
Non-current receivables	**$ 96**	**$ 98**	$ 114	$ 117
Sinking funds (including current portion due in one year)	**275**	**272**	279	274
Long-term debt (including current portion due in one year)	**(31,220)**	**(29,645)**	(29,210)	(27,945)
First Nations liabilities (non-current portion)	**(439)**	**(452)**	(444)	(470)
Other liabilities (non-current portion)	**(421)**	**(410)**	(397)	(386)

Hedges

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

(in millions)	**September 30, 2025 Fair Value**	March 31, 2025 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contract assets (cash flow hedges for US$ denominated long-term debt)	**$ 47**	$ 59
Foreign currency contract assets (cash flow hedges for EURO€ denominated long-term debt)	**45**	14
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)	**-**	(6)
	92	67
Non-Designated Derivative Instruments:		
Interest rate contract assets	**49**	41
Interest rate contract liabilities	**(41)**	(99)
Foreign currency contract assets	**6**	21
Commodity derivative assets	**214**	231
Commodity derivative liabilities	**(141)**	(171)
	87	23
Net assets	**$ 179**	$ 90

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

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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(in millions)	For the three months ended September 30 **2025**	2024	For the six months ended September 30 **2025**	2024
Deferred inception gains, beginning of the period	**$ 58**	$ 31	**$ 70**	$ 31
New transactions	**1**	(5)	**2**	(3)
Amortization	**(4)**	11	**(14)**	9
Foreign currency translation (gains) losses	**1**	-	**(2)**	-
Deferred inception gains, end of the period	**$ 56**	$ 37	**$ 56**	$ 37

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.

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.

**NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2025**

The following tables present the financial instruments measured at fair value for each hierarchy level as at September 30, 2025 and March 31, 2025:

As at September 30, 2025 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets (liabilities) carried at fair value:				
Short-term investments	$ 69	$ -	$ -	$ 69
Derivatives financial instrument assets	65	167	129	361
Derivatives financial instrument liabilities	(18)	(85)	(79)	(182)
	$ 116	$ 82	$ 50	$ 248

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

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the six months ended September 30, 2025, there were no commodity transfers between Level 1 to Level 2 (2024 – no transfers).

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 six months ended September 30, 2025 and 2024:

(in millions)	
Balance as at April 1, 2025	**$ 61**
Realized and unrealized gains	292
Transfers	-
Settlements	(301)
Foreign exchange	(2)
Balance as at September 30, 2025	**$ 50**

(in millions)	
Balance as at April 1, 2024	**$ (94)**
Realized and unrealized gains	258
Transfers	1
Settlements	(188)
Foreign exchange	(1)
Balance as at September 30, 2024	**$ (24)**

During the period, there were no commodity derivatives transfers (2024 – $1 million of transfers from Level 2 to Level 3).

During the three and six months ended September 30, 2025, unrealized gains of $147 million and $60 million, respectively (2024 – unrealized gains of $2 million and $29 million, respectively) were recognized on Level

3 derivative commodity instruments still on hand. These gains and losses were recognized in trade revenues.

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

The key unobservable inputs in the valuation of certain Level 3 financial instruments includes components of forward commodity prices and delivery or receipt volumes. A sensitivity analysis was prepared using the Company's assessment of a reasonably possible change in various components of forward prices and volumes of 10 per cent. Forward commodity prices used in determining Level 3 base fair value at September 30, 2025 range between $28-$223 per MWh and a 10 per cent increase/decrease in certain components of these prices would decrease/increase fair value by $165 million. A 10 per cent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $6 million.

Note 15: Other Non-Current Liabilities

(in millions)	***As at September 30*** **2025**	*As at March 31* 2025
Provisions		
Environmental liabilities	**$ 249**	$ 279
Decommissioning obligations	**99**	83
Other	**85**	77
	433	439
First Nations liabilities	**457**	462
Other contributions	**210**	213
Other liabilities	**479**	458
	1,579	1,572
Less: Current portion, included in accounts payable and accrued liabilities	**(142)**	(149)
	$ 1,437	$ 1,423

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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Note 16: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

For the six months ended September 30 (in millions)		**2025**		2024
Restricted Cash	**$**	**35**	$	17
Accounts receivable, accrued revenue, prepaid expenses and other non-current assets		**(87)**		161
Inventories		**(39)**		(56)
Accounts payable, accrued liabilities and other non-current liabilities		**(3)**		(204)
Unearned revenues, customer credits and contributions in aid		**113**		(19)
Post-employment benefits		**(9)**		-
	$	**10**	$	(101)

Non-Cash Investing Transactions:

For the six months ended September 30 (in millions)		**2025**		2024
Contributions in kind received for property, plant and equipment	**$**	**51**	$	60

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.