British Columbia Hydro and Power Authority

2018/19

SECOND QUARTER REPORT

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, 2018 and should be read in conjunction with the MD&A presented in the 2018 Annual Service Plan Report, the 2018 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 six months ended September 30, 2018.

The Company applies accounting standards as prescribed by the Province of British Columbia (the Province) which combines the accounting principles of International Financial Reporting Standards (IFRS) with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980), except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards). 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, 2018 was $34 million, $2 million higher than the same period in the prior fiscal year. The increase was primarily due to higher domestic revenues of $58 million due to higher average customer rates reflecting an average rate increase as approved by the British Columbia Utilities Commission (BCUC) of 3.0 per cent effective April 1, 2018. This was partially offset by $19 million higher amortization and depreciation, higher domestic cost of energy of $17 million mainly as a result of higher planned purchases from Independent Power Producers (IPPs), and $11 million higher finance charges.

- Net income for the six months ended September 30, 2018 was $114 million, $10 million lower than the same period in the prior fiscal year. The decrease was primarily due to higher domestic cost of energy of $49 million mainly as a result of higher planned purchases from IPPs, $38 million higher amortization and depreciation, $24 million higher finance charges, and $17 million higher personnel expenses. This was partially offset by higher domestic revenues of $119 million due to higher average customer rates reflecting an average rate increase as approved by the British Columbia Utilities Commission (BCUC) of 3.0 per cent effective April 1, 2018.

- Water inflows to the system during the six months ended September 30, 2018 were 92 per cent of average compared to 98 per cent of average in the same period in the prior fiscal year. The lower water inflows in fiscal 2019 compared to the same period in the prior fiscal year were the result of persistent dry weather across the province and significantly below average snowpack in the Peace region.

- Capital expenditures, before contributions in aid of construction, for the three and six months ended September 30, 2018 were $1,985 million and $2,524 million, respectively. BC Hydro continues to invest significantly in capital projects/programs to refurbish its ageing infrastructure and build new assets for future growth, including Site C, Downtown Vancouver Electricity Supply: West End Strategic Property Purchase, John Hart Generating Station Replacement, Distribution Wood Poles Replacements, Bridge River 2 Units 5 and 6 Upgrade, and Peace Region Electricity Supply. In addition, on July 26, 2018, the Company completed the purchase of the remaining two-thirds interest in Waneta Dam.

- In January 2018, two Treaty 8 First Nations (West Moberly and Prophet River) each filed treaty infringement claims. These claims assert, among other things, that the Site C Project is an infringement of their rights under Treaty 8. West Moberly First Nations then filed an application for an interim injunction seeking to stop the Site C Project pending the trial of the treaty claim. The injunction hearing began in late July 2018 and concluded in early September 2018. In late October, after the quarter end, the B.C. Supreme Court dismissed the application for the injunction that could have stopped some, or all, construction work on Site C.

CONSOLIDATED RESULTS OF OPERATIONS

	For the three months ended September 30			*For the six months ended September 30*		
($ in millions)	**2018**	2017	Change	**2018**	2017	Change
Total Revenues	**$ 1,542**	$ 1,381	$ 161	**$ 3,063**	$ 2,846	$ 217
Net Income	**$ 34**	$ 32	$ 2	**$ 114**	$ 124	$ (10)
Capital Expenditures	**$ 1,985**	$ 559	$ 1,426	**$ 2,524**	$ 1,135	$ 1,389
GWh Sold (Domestic)	**13,288**	14,942	(1,654)	**25,921**	27,767	(1,846)

($ in millions)	***As at September 30, 2018***	*As at March 31, 2018*	Change
Total Assets	**$ 35,567**	$ 33,742	$ 1,825
Shareholder's Equity	**$ 5,522**	$ 5,456	$ 66
Accrued Payment to the Province	**$ 59**	$ 159	$ (100)
Retained Earnings	**$ 5,402**	$ 5,347	$ 55
Debt to Equity	**80 : 20**	79: 21	n/a
Number of Domestic Customer Accounts	**2,033,001**	2,018,044	14,957
Total Reservoir Storage (GWh)	**23,405**	10,877	12,528

REVENUES

For the three and six months ended September 30, 2018, total revenues, after regulatory account transfers, of $1,542 million and $3,063 million, respectively, were $161 million or 12 per cent and $217 million or 8 per cent higher than same period in the prior fiscal year. The increase over the prior fiscal year for the three months ended September 30, 2018 was due to higher trade revenue of $103 million and higher domestic revenues of $58 million. The increase over the prior fiscal year for the six months ended September 30, 2018 was due to higher domestic revenues and trade revenues of $119 million and $98 million.

The table below shows revenues before regulatory account transfers, the amount of regulatory account transfers, and total revenues after regulatory account transfers.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the three months ended September 30	**2018**	2017	**2018**	2017	**2018**	2017
Domestic Revenues						
Residential	**$ 401**	$ 386	**3,461**	3,460	**$ 115.86**	$ 111.56
Light industrial and commercial	**460**	467	**4,540**	4,759	**101.32**	98.13
Large industrial	**219**	197	**3,550**	3,312	**61.69**	59.48
Other sales	**200**	170	**1,737**	3,411	**115.14**	49.84
Total Domestic Revenue Before Regulatory Transfers	**1,280**	1,220	**13,288**	14,942	**96.33**	81.65
Regulatory transfers	**6**	8	-	-	-	-
Total Domestic Revenues	**$ 1,286**	$ 1,228	**13,288**	14,942	**$ 96.78**	$ 82.18
Trade Revenues						
Gross electricity and gas	**$ 378**	$ 306	**5,790**	6,987	**$ 56.34**	$ 37.80
Less: forward electricity and gas purchases	**(122)**	(153)	-	-	-	-
Total Trade Revenues [1]	**$ 256**	$ 153	**5,790**	6,987	**$ 44.21**	$ 21.90
Total Revenues	**$ 1,542**	$ 1,381	**19,078**	21,929	**$ 80.83**	$ 62.98

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the six months ended September 30	**2018**	2017	**2018**	2017	**2018**	2017
Domestic Revenues						
Residential	**$ 834**	$ 822	**7,231**	7,258	**$ 115.34**	$ 113.25
Light industrial and commercial	**927**	897	**9,180**	9,120	**100.98**	98.36
Large industrial	**411**	379	**6,779**	6,490	**60.63**	58.40
Other sales	**280**	253	**2,731**	4,899	**102.53**	51.64
Total Domestic Revenue Before Regulatory Transfers	**2,452**	2,351	**25,921**	27,767	**94.60**	84.67
Regulatory transfers	**124**	106	-	-	-	-
Total Domestic Revenues	**$ 2,576**	$ 2,457	**25,921**	27,767	**$ 99.38**	$ 88.49
Trade Revenues						
Gross electricity and gas	**$ 653**	$ 660	**13,423**	17,114	**$ 41.60**	$ 34.22
Less: forward electricity and gas purchases	**(166)**	(271)	-	-	-	-
Total Trade Revenues [1]	**$ 487**	$ 389	**13,423**	17,114	**$ 36.28**	$ 22.73
Total Revenues	**$ 3,063**	$ 2,846	**39,344**	44,881	**$ 77.85**	$ 63.41

[1] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer and this is reflected in the cost of energy table.*

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

Domestic Revenues

Domestic revenues for the three months ended September 30, 2018 were $1,286 million, an increase of $58 million, or 5 per cent, compared to the same period in the prior fiscal year. The increase over the prior fiscal year, before regulatory account transfers, was primarily due to higher average customer rates that reflect the 3.0 per cent rate increase as approved by the BCUC effective April 1, 2018. The increase is also due to higher other sales, which includes revenues from July 26, 2018 in relation to the sale of two-thirds of the production from the Waneta Dam and Generating Facility (Waneta), and higher surplus sales revenue driven by higher prices, despite lower volumes (1,470 GWh compared to 3,119 GWh in the same period in the prior fiscal year). Large industrial revenue was also higher due to increased activity in the oil and gas sector. These higher revenues were partially offset by lower consumption from light industrial and commercial customers.

Domestic revenues for the six months ended September 30, 2018 were $2,576 million, an increase of $119 million or 5 per cent compared to the same period in the prior fiscal year. The increase over the prior fiscal year, before regulatory account transfers, was primarily due to higher average customer rates that reflect the 3.0 per cent rate increase as approved by the BCUC effective April 1, 2018. The increase is also due to higher other sales, which includes revenues related to the purchase of the remaining two-thirds of Waneta, as well as higher large industrial revenue due to increased activity in the oil and gas sector.

In addition, there were $18 million higher regulatory account transfers related to the Rate Smoothing account, Non-Heritage Deferral Account (NHDA), and Heritage Deferral Account (HDA) during the six month period ended September 30, 2018 as compared to the same period in the prior year. Changes to regulatory account balances are discussed in the Regulatory Transfers section.

Variances between actual and planned load are deferred to the NHDA and variances between actual and planned other energy sales are deferred to the HDA and NHDA.

In terms of volumes, for the three months ended September 30, 2018, excluding surplus sales, domestic load was consistent with the prior year, with higher large industrial revenue (238 GWh higher) largely offset by lower light industrial and commercial revenue (219 GWh lower). For the six months ended September 30, 2018, excluding surplus sales, domestic load was slightly higher than the prior year primarily driven by higher large industrial revenue in the oil and gas sector.

Trade Revenues

Powerex, a wholly owned subsidiary of the Company, is an active participant in western energy markets, buying and selling wholesale power, natural gas, ancillary services, clean and renewable power, and other environmental products.

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

Total trade revenues for the three months ended September 30, 2018 were $256 million, an increase of $103 million or 67 per cent compared to the same period in the prior fiscal year. The increase in trade energy revenue was primarily driven by higher average energy sales prices for the period.

Total trade revenues for the six months ended September 30, 2018 were $487 million, an increase of $98 million or 25 per cent compared to the same period in the prior fiscal year. The increase in trade energy revenue was primarily driven by higher average energy sales prices for the period.

Variances between actual and planned trade revenues are transferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the three and six months ended September 30, 2018, total operating expenses, after regulatory account transfers, of $1,330 million and $2,600 million, respectively, were $148 million and $203 million or 13 percent and 8 percent higher than the same period in the prior fiscal year. The increase over the prior fiscal year for the three months ended September 30, 2018 was primarily due to higher energy costs of $120 million, and higher amortization and depreciation of $19 million. The increase over the prior fiscal year for the six months ended September 30, 2018 was primarily due to higher energy costs of $147 million, and higher amortization and depreciation of $38 million.

Energy Costs

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

Total energy costs after regulatory transfers for the three months ended September 30, 2018 were $690 million, $120 million or 21 per cent higher than the same period in the prior fiscal year. The increase was primarily due to higher trade energy costs of $103 million and higher domestic energy costs of $17 million.

Total energy costs after regulatory transfers for the six months ended September 30, 2018 were $1,297 million, $147 million or 13 per cent higher than the same period in the prior fiscal year. The increase was primarily due to higher trade energy costs of $98 million and higher domestic energy costs of $49 million. The table below shows energy costs before regulatory account transfers, the amount of regulatory account transfers, and total energy costs after regulatory account transfers.

for the three months ended September 30	*(in millions)* **2018**	2017	*(gigawatt hours)* **2018**	2017	*($ per MWh)* [2] **2018**	2017
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 84**	$ 80	**10,197**	11,695	**$ 8.24**	$ 6.84
Purchases from Independent Power Producers	**363**	395	**4,162**	4,318	**87.22**	91.48
Other electricity purchases - Domestic	**-**	1	**11**	9	**-**	111.11
Gas and transportation for thermal generation	**4**	3	**46**	-	**86.96**	-
Transmission charges and other expenses	**4**	7	**22**	22	**-**	-
Columbia River Treaty Related Agreements	**(47)**	(29)	**-**	-	**-**	-
Allocation from (to) trade energy	**3**	**1**	**(10)**	(67)	**41.15**	29.59
Total Domestic Cost of Energy Before Regulatory Transfers	**411**	458	**14,428**	15,977	**28.49**	28.67
Energy deferral regulatory transfers	**70**	6	**-**	-	**-**	-
Total Domestic Energy Costs	**$ 481**	$ 464	**14,428**	15,977	**$ 33.34**	$ 29.04
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 164**	$ 168	**5,733**	7,090	**$ 27.67**	$ 23.61
Less: forward electricity and gas purchases	**(122)**	(153)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**42**	15	**-**	-	**-**	-
Transmission charges and other expenses	**73**	64	**-**	-	**-**	-
Allocation (to) from domestic energy	**(3)**	(1)	**10**	67	**41.15**	29.59
Total Trade Cost of Energy Before Regulatory Transfers	**112**	78	**5,743**	7,157	**19.50**	10.90
Trade net margin regulatory transfer	**97**	28	**-**	-	**-**	-
Total Trade Energy Costs	**$ 209**	$ 106	**5,743**	7,157	**$ 36.39**	$ 14.81
Total Energy Costs	**$ 690**	$ 570	**20,171**	23,134	**$ 34.21**	$ 24.64

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

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

for the six months ended September 30	*(in millions)* **2018**	2017	*(gigawatt hours)* **2018**	2017	*($ per MWh)* [2] **2018**	2017
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 168**	$ 161	**18,916**	21,293	**$ 8.88**	$ 7.56
Purchases from Independent Power Producers	**678**	710	**8,576**	8,521	**79.06**	83.32
Other electricity purchases - Domestic	**1**	1	**51**	32	**19.61**	31.25
Gas and transportation for thermal generation	**8**	5	**71**	-	**112.68**	-
Transmission charges and other expenses	**8**	8	**47**	47	**-**	-
Columbia River Treaty Related Agreements	**(47)**	(29)	**-**	-	**-**	-
Allocation from (to) trade energy	**11**	2	**412**	85	**30.86**	17.81
Total Domestic Cost of Energy Before Regulatory Transfers	**827**	858	**28,073**	29,978	**29.46**	28.62
Energy deferral regulatory transfers	**77**	(3)	**-**	-	**-**	-
Total Domestic Energy Costs	**$ 904**	$ 855	**28,073**	29,978	**$ 32.20**	$ 28.52
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 264**	$ 360	**13,935**	17,216	**$ 18.49**	$ 20.70
Less: forward electricity and gas purchases	**(166)**	(271)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**98**	89	**-**	-	**-**	-
Transmission charges and other expenses	**150**	146	**-**	-	**-**	-
Allocation (to) from domestic energy	**(11)**	(2)	**(412)**	(85)	**30.86**	17.81
Total Trade Cost of Energy Before Regulatory Transfers	**237**	233	**13,523**	17,131	**17.53**	13.60
Trade net margin regulatory transfer	**156**	62	**-**	-	**-**	-
Total Trade Energy Costs	**$ 393**	$ 295	**13,523**	17,131	**$ 29.06**	$ 17.22
Total Energy Costs	**$ 1,297**	$ 1,150	**41,596**	47,109	**$ 31.18**	$ 24.41

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

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

Domestic Energy Costs

Domestic energy costs for the three months ended September 30, 2018 were $481 million, $17 million or 4 per cent higher than the same period in the prior fiscal year. The significant variances from the prior fiscal year, before regulatory account transfers, included $32 million lower costs from IPPs largely driven by fewer deliveries from hydro generating IPPs due to a dry summer, as well as higher recoveries of $18 million from net water releases associated with the Columbia River Treaty related agreements.

Domestic energy costs for the six months ended September 30, 2018 were $904 million, $49 million or 6 per cent higher than the same period in the prior fiscal year. Before regulatory account transfers, domestic energy costs were $31 million lower in the current period, primarily due to $32 million lower costs from IPPs largely driven by a dry summer. In addition, there were higher recoveries of $18 million from net water releases associated with the Columbia River Treaty related agreements.

In addition, there were $64 million higher regulatory account transfers for the three months ended, September 30, 2018, and $80 million higher regulatory account transfers for the six months September 30, 2018, as compared to the respective periods in the prior year, related to the HDA and NHDA. Variances between actual and planned domestic energy costs are transferred to the HDA and NHDA. Changes to regulatory account balances are discussed in the *Regulatory Transfers* section.

Trade Energy Costs

Total trade energy costs before regulatory account transfers for the three months ended September 30, 2018 were $112 million, an increase of $34 million or 44 per cent compared to the same period in the prior fiscal year. The increase in trade energy costs was primarily driven by higher average energy purchase prices for the period.

Total trade energy costs before regulatory account transfers for the six months ended September 30, 2018 were $237 million, comparable to the same period in the prior fiscal year of $233 million.

Variances between actual and planned trade costs are transferred to the TIDA.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system during six months ended September 30, 2018 were 92 per cent of average compared to 98 per cent of average in the same period of prior fiscal year. The lower water inflows in fiscal 2019 compared to the same period in the prior fiscal year were the result of persistent dry weather across the province and significantly below average snowpack in the Peace region.

Total reservoir storage as at September 30, 2018 was 23,405 GWh, a decrease of 3,554 GWh compared to total reservoir storage as at September 30, 2017 of 26,959 GWh. System energy storage dropped below the prior 10-year historical range (25,380 to 30,755 GWh) due to low inflows, strong energy prices resulting in higher exports, and a low starting storage level for fiscal 2019.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and six months ended September 30, 2018 were $131 million and $287 million, respectively, $5 million and $17 million, respectively higher than the prior fiscal year primarily due to an increase in the number of full time employees. The increased number of full time employees was primarily due to BC Hydro's Workforce Optimization program, which replaced some external service providers with internal staff to reduce costs and deliver on our business objectives.

Materials and External Services

Materials and External Services primarily include materials, supplies, and contractor fees. Materials and external services for the three and six months ended September 30, 2018 were $145 million and $290 million, respectively, $1 million and $10 million lower than the prior fiscal year primarily due to BC Hydro's Workforce Optimization program which replaced some external service providers with full-time employees to reduce costs and deliver on our business objectives.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and the amortization of certain regulatory assets and liabilities. For the three and six months ended September 30, 2018, amortization and depreciation expense was $319 million and $638 million, $19 million and $38 million higher than the prior fiscal year primarily due to higher amortization of regulatory accounts and higher depreciation of property, plant and equipment due to an increase in assets in service. For the three and six months ended September 30, 2018, the amortization and depreciation expense included $104 million and $208 million respectively (three and six months ended September 30, 2017 - $92 million and $185 million, respectively) of amortization of regulatory account balances, which is the regulatory mechanism to recover the regulatory account balances in rates.

Grants, Taxes and Other Costs

As a Crown Corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants, taxes and other costs for the three and six months ended September 30, 2018 were $80 million and $158 million, respectively, comparable to $80 million and $157 million, respectively, in the same period in the prior fiscal year.

Capitalized Costs

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Certain overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS Property, Plant & Equipment Regulatory Account. These transfers are amortized over 40 years which approximates the composite average life of the Property, Plant & Equipment. In addition, starting in fiscal 2013, the ongoing impact of this change is being included in rates over a 10-year period through transfers to the IFRS Property, Plant & Equipment Regulatory Account as approved by the BCUC. As such, each year, 1/10 more of ineligible costs will be charged to operating costs such that by the end of year ten, all ineligible costs will be charged to operating costs.

Capitalized costs for the three and six months ended September 30, 2018 were $35 million and $70 million, respectively, compared to capitalized costs of $40 million and $80 million, respectively, in the same period in the prior fiscal year. The decrease in capitalized cost is consistent with the additional ineligible costs being charged to operating costs as noted above.

FINANCE CHARGES

Finance charges for the three and six months ended September 30, 2018 were $178 million and $349 million, respectively, $11 million and $24 million, respectively, higher than the same period in the prior fiscal year. The increase was primarily due to higher outstanding debt and higher interest rates for long-term debt borrowings, and lower interest income on the Mining Customer Payment plan. This increase was partially offset by higher pension plan income and higher interest capitalized during construction.

REGULATORY TRANSFERS

The Company presents its results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS combined with ASC 980 to reflect the rate-regulated environment in which the Company operates. These Prescribed Standards allow for the deferral of costs and recoveries that under IFRS may otherwise be included in the determination of total comprehensive income. The deferred amounts are either recovered or refunded through future rate adjustments.

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, to better match costs and benefits for different generations of customers, smooth out the rate impact of large non-recurring costs, and defer to future periods differences between forecast and actual costs or revenues. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which are then 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 September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Energy Deferral Accounts				
Heritage Deferral Account	$ (91)	$ (57)	**$ (95)**	$ (61)
Non-Heritage Deferral Account	(39)	(15)	**5**	21
Trade Income Deferral Account	(94)	(27)	**(150)**	(59)
	(224)	(99)	**(240)**	(99)
Forecast Variance Accounts				
Total Finance Charges	14	(7)	**12**	(12)
Rate Smoothing	70	61	**141**	121
Debt Management	(92)	(61)	**(102)**	(65)
Other	5	15	**5**	15
	(3)	8	**56**	59
Capital-Like Accounts				
Demand-Side Management	17	15	**28**	24
IFRS Property, Plant & Equipment	17	23	**34**	45
	34	38	**62**	69
Non-Cash Accounts				
Environmental Provisions & Costs	(6)	(7)	**(4)**	(6)
First Nations Provisions & Costs	5	5	**12**	11
Other	(2)	(1)	**(3)**	(2)
	(3)	(3)	**5**	3
Amortization of regulatory accounts	(104)	(92)	**(208)**	(185)
Interest on regulatory accounts	11	16	**24**	33
Net increase/(reduction) in regulatory accounts	**$ (289)**	**$ (132)**	**$ (301)**	$ (120)

The net regulatory asset balance as at September 30, 2018 was $4,839 million compared to $5,455 million as at March 31, 2018. $315 million of the decrease was due to the Company adopting IFRS 15, *Revenue from Contracts with Customers* on April 1, 2018, which resulted in a decrease to the opening net regulatory asset balance. Refer to Note 2 in the Unaudited Condensed Consolidated Interim Financial Statements for more detail on the impact of the adoption of IFRS 15.

As shown in the table above, excluding the $315 million change regarding the opening balance, there was a net reduction of $289 million and $301 million to the Company’s regulatory accounts for the three and six months ended September 30, 2018 compared to a net reduction of $132 million and $120 million, respectively, in the same period in the prior fiscal year.

Net reductions to the regulatory accounts during the six months ended September 30, 2018 included:

- Net amortization of $208 million. Amortization is the regulatory mechanism to recover the regulatory account balances in rates;
- $240 million to the energy deferral accounts, primarily due to higher trade net income and lower domestic cost of energy; and

- $102 million to the Debt Management Regulatory Account primarily as a result of an increase in forward interest rates compared to March 31, 2018, which resulted in net gains on the future debt interest rate hedges.

These net reductions were partially offset by:

- $141 million of planned additions to the Rate Smoothing Regulatory Account to smooth the impacts of the rate increases during the 10 Year Rates Plan period;

- $34 million of planned additions to the IFRS Property, Plant & Equipment Regulatory Account for smoothing the rate impact of overhead costs not eligible for capitalization under IFRS as they are not considered directly attributable to the construction of capital assets;

- $28 million of additions to the Demand-Side Management Regulatory Account for expenditures incurred to support energy conservation; and

- Interest on regulatory accounts of $24 million.

BC Hydro has regulatory mechanisms in place to collect 25 of 28 regulatory accounts in use or with balances at September 30, 2018 in rates over various periods, which represent approximately 70 per cent of the net regulatory asset balance.

PAYMENT TO THE PROVINCE

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

The fiscal 2018 Payment to the Province was $159 million and was paid in June 2018. As a result, the Payment for fiscal 2019 will be $59 million and the Company has accrued $59 million as at September 30, 2018.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the six months ended September 30, 2018 was $867 million, compared to $790 million in the same period in the prior fiscal year. The increase was primarily due to cash received from higher domestic revenues, higher trade gross margins and lower domestic costs offset against lower cash inflow from changes in working capital, and higher finance charges.

The long-term debt balance net of sinking funds as at September 30, 2018 was $22,097 million compared to $20,182 million as at March 31, 2018. Long-term debt increased primarily to fund capital expenditures and the increase was mainly a result of an increase in long-term bond issuances for net proceeds of $2,418 million ($2,450 million par value). This increase was partially offset by long-term bond redemptions totaling $457 million par value, and net foreign exchange gains of $34 million.

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 September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Transmission lines and substations replacements and expansion	**$ 181**	$ 101	**$ 261**	$ 214
Generation replacements and expansion	**113**	135	**205**	272
Distribution system improvements and expansion	**124**	129	**243**	249
General, including technology, vehicles and buildings	**28**	43	**61**	85
Waneta two-thirds interest acquisition	**1,219**	-	**1,219**	-
Site C	**320**	151	**535**	315
Total Capital Expenditures	**$ 1,985**	$ 559	**$ 2,524**	$ 1,135

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.

Transmission lines and substation capital expenditures include expenditures on the following projects/programs: Downtown Vancouver Electricity Supply: West End Strategic Property Purchase, Peace Region Electricity Supply, Fort St. John and Taylor Electric Supply, Transmission Wood Structure and Framing Replacement, North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Version 5 Compliance Impact to Transmission and Distribution Stations, 138kV Circuit Breaker Replacement, Horne Payne Substation Upgrade, Kamloops Substation, and South Surrey Area Reinforcement.

Generation capital expenditures include expenditures for the following projects: John Hart Generating Station Replacement, Bridge River 2 Units 5 and 6 Upgrade, Cheakamus Unit 1 and Unit 2 Generator Replacement, Ruskin Dam Safety and Powerhouse Upgrade, Bridge River 2 – Strip and Recoat Penstock 1 Interior, W.A.C Bennett Dam Riprap Upgrade, Mica Powerhouse Cranes Upgrade, G.M. Shrum G1-G10 Control System Upgrade, and Mica Townsite Augment Accommodations Capacity.

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

The Waneta two-thirds interest acquisition is BC Hydro’s purchase of the remaining two-third interest in the Waneta Dam and associated assets for $1.2 billion from Teck Metals Ltd. (Teck).

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

RATE REGULATION

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

BC Hydro Waneta Transaction

On October 30, 2017, BC Hydro submitted an Application to the BCUC under section 44.2 of the Utilities Commission Act for approval to purchase Teck's two-third interest in the Waneta Dam and associated assets for $1.2 billion. The purchase agreement includes a 20 year agreement, whereby BC Hydro has contracted to sell two-thirds of the production of Waneta. Teck has an option to extend the agreement for a further 10 years. The Waneta dam is located near the mouth of the Pend d'Oreille River near Trail, BC, and has a generating capacity of 2,670 GWh per year.

On July 18, 2018, the BCUC issued Order No. G-130-18 approving the Waneta Transaction. The BCUC approved our requested expenditure schedule, purchase of transmission assets and transaction costs. On July 26, 2018, BC Hydro completed this transaction.

BCUC Inquiry of Expenditures Related to the Adoption of the SAP Platform

In December 2015, a formal complaint was filed with the BCUC, making a number of statements and allegations regarding the evidence provided in the Fiscal 2009 – Fiscal 2010 Revenue Requirements Application concerning BC Hydro's adoption of SAP as the primary technology platform. In May 2016, the BCUC ordered an inquiry to establish facts regarding BC Hydro's SAP-related expenditures, including a review of the effectiveness of financial controls and project governance processes and whether BC Hydro's SAP-related disclosures to the BCUC were appropriate, reasonable and in accordance with the *Utilities Commission Act*.

On September 7, 2018, the BCUC issued a Report into the Inquiry of Expenditures Related to the Adoption of the SAP Platform, containing its findings and recommendations. BC Hydro supports the BCUC's findings and is acting on the recommendations.

Capital Expenditures and Projects Review

The BCUC initiated a review in May 2016 to review the regulatory oversight of BC Hydro's capital expenditures and projects. At BC Hydro's request, the BCUC scheduled the proceeding to commence following the Fiscal 2017 – Fiscal 2019 Revenue Requirements Application decision. BC Hydro submitted the initial proposal in April 2018, which included draft Capital Filing Guidelines. These draft Guidelines expand upon the previous capital project filing guidelines by including the review of capital expenditures and projects in a revenue requirements proceeding, and better aligning capital project regulatory applications with our current capital planning processes. In September 2018, the BCUC determined that interveners would be allowed to submit evidence into the proceeding. Evidence from the Commercial Energy Consumers Association of BC (CEC) was filed in November, followed by a round of information requests on that evidence. BC Hydro will then have the option to file rebuttal evidence in November. This will be followed by the final argument phase in January or February 2019.

Supply Chain Applications Project Application

In December 2016, BC Hydro submitted the Supply Chain Applications Project Application under section 44.2 for acceptance of expenditures for a new SAP IT platform to meet BC Hydro's current and future business needs, and provide benefits for supply chain activities throughout BC Hydro. The project's total capital cost is estimated to be between $60 million and $79 million with a planned in service date in the fourth quarter of fiscal 2020. In October 2017, the BCUC issued Order No.G-158-17, approving expenditures required to complete the Phase One (Definition Phase) of the Project, and directing BC Hydro to file a Phase Two Verification Report at the conclusion of Phase One.

In October 2018, BC Hydro completed Phase One of the Project, and filed the Verification Report with the BCUC. The Verification Report included an update on project costs, benefits, scope, risks and schedule, and a request for acceptance of the capital expenditures required for Phase Two (Implementation Phase) of the Project, all within the authorized amount of $79 million.

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, to smooth the impact of large, non-recurring costs 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 2017-2019 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 five categories: energy availability, domestic demand for energy, energy market prices, deliveries from electricity purchase agreement contracts, and interest rates. 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 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 doing so, BC Hydro attempts to optimize the combined effects of these elements and reduce the net cost of energy for our customers.

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 Annual Service Plan Report for the year ended March 31, 2018. 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 2018 forecast net income for fiscal 2019 at $712 million which is consistent with the amount required by Order in Council No. 590/2016.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, interest rates, and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The Service Plan forecast for fiscal 2019 assumed average water inflows (100 per cent of average), domestic sales of 52,664 GWh, average market energy prices of US $21.43/MWh, short-term interest rates of 1.72 per cent, and a Canadian to US dollar exchange rate of US $0.8088.

BC Hydro filed an updated forecast with the Province in November 2018. The updated forecast for fiscal 2019 assumes below average water inflows (94 percent of average), domestic sales of 52,354 GWh, average market energy prices of U.S. $31.55/MWh, short-term interest rates of 1.65 per cent and a Canadian to US dollar exchange rate of US $0.7721. The net income forecast for fiscal 2019 remains at $712 million.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Revenues				
Domestic (Note 3)	**$ 1,286**	$ 1,228	**$ 2,576**	$ 2,457
Trade (Note 3)	**256**	153	**487**	389
	1,542	1,381	**3,063**	2,846
Expenses				
Operating expenses (Note 4)	**1,330**	1,182	**2,600**	2,397
Finance charges (Note 5)	**178**	167	**349**	325
Net Income	**34**	32	**114**	124
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)	**(16)**	(11)	**(23)**	8
Reclassification to income of derivatives designated as cash flow hedges (Note 14)	**28**	42	**34**	46
Foreign currency translation losses	**(2)**	(5)	**-**	(8)
Other Comprehensive Income	**10**	26	**11**	46
Total Comprehensive Income	**$ 44**	$ 58	**$ 125**	$ 170

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 2018***	*As at March 31* 2018
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 172**	$ 42
Restricted cash	**28**	77
Accounts receivable and accrued revenue	**617**	733
Inventories (Note 7)	**204**	144
Prepaid expenses	**235**	167
Current portion of derivative financial instrument assets (Note 14)	**66**	174
	1,322	1,337
Non-Current Assets		
Property, plant and equipment (Note 8)	**27,160**	25,083
Intangible assets (Note 8)	**587**	591
Regulatory assets (Note 9)	**5,735**	5,892
Derivative financial instrument assets (Note 14)	**157**	156
Other non-current assets (Note 10)	**606**	683
	34,245	32,405
	$ 35,567	$ 33,742
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 1,468**	$ 1,621
Current portion of long-term debt (Note 11)	**3,056**	3,344
Current portion of derivative financial instrument liabilities (Note 14)	**42**	112
	4,566	5,077
Non-Current Liabilities		
Long-term debt (Note 11)	**19,227**	17,020
Regulatory liabilities (Note 9)	**896**	437
Derivative financial instrument liabilities (Note 14)	**18**	66
Contributions in aid of construction	**1,935**	1,874
Post-employment benefits (Note 13)	**1,495**	1,474
Other non-current liabilities (Note 15)	**1,908**	2,338
	25,479	23,209
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**5,402**	5,347
Accumulated other comprehensive income	**60**	49
	5,522	5,456
	$ 35,567	$ 33,742

Commitments (Note 8)

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

Approved on behalf of the Board:

Kenneth G. Peterson
Chair, Board of Directors

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains (Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2017	$ 83	$ (56)	$ 27	$ 60	$ 4,822	$ 4,909
Payment to the Province (Note 12)	-	-	-	-	(159)	(159)
Comprehensive Income (Loss)	(8)	54	46	-	124	170
Balance as at September 30, 2017	$ 75	$ (2)	$ 73	$ 60	$ 4,787	$ 4,920
Balance as at April 1, 2018	$ 78	$ (29)	$ 49	$ 60	$ 5,347	$ 5,456
Payment to the Province (Note 12)	-	-	-	-	(59)	(59)
Comprehensive Income	-	11	11	-	114	125
Balance as at September 30, 2018	$ 78	$ (18)	$ 60	$ 60	$ 5,402	$ 5,522

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the six months ended September 30* **2018**	2017
Operating Activities		
Net income	**$ 114**	$ 124
Regulatory account transfers (Note 9)	**93**	(65)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Notes 6 and 9)	**208**	185
Amortization and depreciation expense (Note 6)	**430**	415
Unrealized (gains) losses on mark-to-market of financial instruments	**(80)**	(41)
Employee benefit plan expenses	**52**	53
Interest accrual	**421**	391
Other items	**(23)**	36
	1,215	1,098
Changes in:		
Restricted cash	**49**	15
Accounts receivable and accrued revenue	**157**	205
Prepaid expenses	**(88)**	(25)
Inventories	**(60)**	(14)
Accounts payable, accrued liabilities and other non-current liabilities	**(74)**	(134)
Contributions in aid of construction	**68**	61
Other non-current assets	**8**	(25)
	60	83
Interest paid	**(408)**	(391)
Cash provided by operating activities	**867**	790
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(2,570)**	(1,045)
Cash used in investing activities	**(2,570)**	(1,045)
Financing Activities		
Long-term debt:		
Issued (Note 11)	**2,418**	569
Retired (Note 11)	**(457)**	(40)
Receipt of revolving borrowings	**3,702**	4,596
Repayment of revolving borrowings	**(3,709)**	(4,882)
Payment to the Province (Note 12)	**(159)**	-
Other items	**38**	28
Cash provided by financing activities	**1,833**	271
Increase in cash and cash equivalents	**130**	16
Cash and cash equivalents, beginning of period	**42**	49
Cash and cash equivalents, end of period	**$ 172**	$ 65

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, 2018

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 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), Powertech Labs Inc. (Powertech), and Columbia Hydro Constructors Ltd. (Columbia), (collectively with BC Hydro, the Company). All intercompany transactions and balances are eliminated on consolidation. On July 26, 2018, the Company completed the purchase of the remaining two-thirds interest of Waneta Dam and Generating Facility (Waneta) (Note 8). Prior to this transaction, the Company accounted for its one third interest in Waneta as a joint operation.

NOTE 2: BASIS OF PRESENTATION

Basis of Accounting

These interim financial statements have been prepared in accordance with the significant accounting policies that have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare these interim financial statements in accordance with the accounting principles of International Financial Reporting Standards (IFRS), combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations*, except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively, the Prescribed Standards). The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such regulatory costs and recoveries would be included in the determination of comprehensive income in absence of regulatory deferral.

The impact of the application of ASC 980 on these interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 9.

These interim financial statements have been prepared by management in accordance with principles of IAS 34, *Interim Financial Reporting* and the Prescribed Standards and were prepared using the same accounting policies as described in BC Hydro's 2018 Annual Service Plan Report, except for changes as a result of the adoption of IFRS 15, *Revenue from Contracts with Customers* (IFRS 15) and IFRS 9, *Financial Instruments* (IFRS 9). These interim financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2018 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 November 8, 2018.

The following are the significant accounting policies changes.

IFRS 15 - Revenue from Contracts with Customers

Effective April 1, 2018, the Company adopted IFRS 15, which replaces existing standards IAS 18, *Revenue*, IAS 11, *Construction Contracts* and IFRIC 18, *Transfers of Assets from Customers*. The Company adopted the standard on a modified retrospective basis, under which comparative periods are not restated and the cumulative impact of applying the standard is recognized at the date of initial adoption supplemented by additional disclosures.

The IFRS 15 recognition model is based on the principle of the transfer of control rather than the transfer of risks and rewards used under IAS 18. IFRS 15 applies a five-step model to determine when to recognize revenue and determine the measurement of the revenue.

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

Domestic revenues comprise sales to customers within the province of British Columbia and sales of energy outside the province that are reflected in the Company's domestic load requirements. Other sales outside the province are classified as trade.

A significant portion of the Company's revenue is generated from providing electricity goods and services. Revenue is recognized over time as the Company's customers simultaneously receive and consume the electricity goods and services as it is provided. Revenue is determined on the basis of billing cycles and also includes accruals for electricity deliveries not yet billed.

Energy trading contracts that meet the definition of a financial or non-financial derivative are accounted for at fair value whereby any realized gains and losses and unrealized changes in the fair value are recognized in trade revenues in the period of change. Unrealized changes in the fair value of these contracts are accounted for under IFRS 9.

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

Refer to "Impact of Changes in Accounting Policies" contained below for the cumulative effect of the adoption of IFRS 15 on the Consolidated Statement of Financial Position as at April 1, 2018 and Note 3 for the effect on the Condensed Consolidated Interim Statement of Comprehensive Income for the three and six month period ended September 30, 2018.

IFRS 9 - Financial Instruments

Effective April 1, 2018, the Company adopted IFRS 9, which replaces existing standard IAS 39, *Financial Instruments: Recognition and Measurement* (IAS 39) in accordance with the transitional provisions of the standard. In addition, the Company adopted IFRS 7: *Financial Instruments: Disclosures* – Disclosure amendments and additions from IFRS 9 Implementation.

IFRS 9 addresses the classification, measurement and recognition of financial assets and financial liabilities and supersedes the guidance relating to the classification and measurement of financial instruments in IAS 39. IFRS 9 requires financial assets to be classified into three measurement categories on initial recognition: those measured at fair value through profit and loss (FVTPL), those measured at fair value through other comprehensive income (FVOCI) and those measured at amortized cost. As permitted by the transitional provision for hedge accounting under IFRS 9, the Company has elected to continue with the hedging requirements of IAS 39 and not adopt the hedging requirements of IFRS 9.

The Company determines the classification of its financial assets and liabilities at initial recognition. Classification of financial assets and liabilities is determined based on the business model by which assets and liabilities are managed and their cash flow characteristics. The change in the classification of financial assets and liabilities has been applied retrospectively and did not result in a change in the carrying amount of any financial instruments at the transition date.

A financial asset is measured at FVTPL if it is classified as held for trading or is designated as such upon initial recognition. The Company may designate financial instruments as held at FVTPL when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis. All derivative instruments are categorized as FVTPL unless they are designated as accounting hedges.

Financial assets and liabilities are measured at amortized cost if the business model is to hold the instrument for collection or payment of contractual cash flows and those cash flows are solely principal and interest. If the business model is not to hold the instruments, it is classified as FVTPL. Financial assets and liabilities are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses in the impairment of financial assets.

Under IFRS 9, the financial asset impairment model moves from the 'incurred loss' model in IAS 39 to a single, forward-looking 'expected loss' model. The expected-loss impairment model requires an entity to recognize expected credit losses when financial instruments are initially recognized and to update the amount of expected credit losses recognized at each reporting date to reflect changes in the credit risk of the financial instruments.

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

The adoption of IFRS 9 had no significant impact on the Consolidated Statement of Financial Position as at April 1, 2018. Refer to Note 14 for the effect on the Condensed Consolidated Statement of Comprehensive Income for the three month and six month period ended September 30, 2018.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2018

Impact of Changes in Accounting Policies

(in millions)	*As at March 31* 2018	IFRS 15 Adjustments: Receivables and Unearned Revenue [1]	IFRS 15 Adjustments: Skagit Agreement [2]	*As at April 1* 2018
ASSETS				
Current Assets				
Cash and cash equivalents	$ 42	$ -	$ -	$ 42
Accounts receivable and accrued revenue	810	-	-	810
Inventories	144	-	-	144
Prepaid expenses	167	-	-	167
Current portion of derivative financial instrument assets	174	-	-	174
	1,337	-	-	1,337
Non-Current Assets				
Property, plant and equipment	25,083	-	-	25,083
Intangible assets	591	-	-	591
Regulatory assets	5,892	(1)	-	5,891
Derivative financial instrument assets	156	-	-	156
Other non-current assets	683	(51)	-	632
	32,405	(52)	-	32,353
	$ 33,742	$ (52)	$ -	$ 33,690
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities	$ 1,621	$ -	$ -	$ 1,621
Current portion of long-term debt	3,344	-	-	3,344
Current portion of derivative financial instrument liabilities	112	-	-	112
	5,077	-	-	5,077
Non-Current Liabilities				
Long-term debt	17,020	-	-	17,020
Regulatory liabilities	437	(5)	319	751
Derivative financial instrument liabilities	66	-	-	66
Contributions in aid of construction	1,874	-	-	1,874
Post-employment benefits	1,474	-	-	1,474
Other non-current liabilities	2,338	(47)	(319)	1,972
	23,209	(52)	-	23,157
Shareholder's Equity				
Contributed surplus	60	-	-	60
Retained earnings	5,347	-	-	5,347
Accumulated other comprehensive income	49	-	-	49
	5,456	-	-	5,456
	$ 33,742	$ (52)	$ -	$ 33,690

[1] There was a decrease of $51 million in non-current receivables within other non-current assets and a decrease of $47 million in unearned revenue within other non-current liabilities due to the new prescriptive guidance in IFRS 15 regarding recognition of receivables and related unearned revenue amounts. The net difference of $4 million was recognized in regulatory assets/liabilities.

[2] There was a decrease of $319 million in the unearned revenue liability account within other non-current liabilities as a result of adjusting the measurement of the transaction price due to a significant customer financing component for upfront consideration received under the Skagit River, Ross Lake and the Seven Mile Reservoir on the Pend d'Oreille River agreement (collectively the Skagit River Agreement). To ensure ratepayers receive the benefit of this accounting change, the corresponding increase was transferred to the Heritage Deferral Account regulatory liability balance instead of adjusting retained earnings.

NOTE 3: REVENUE

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

(in millions)	*For the three months ended September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Domestic				
Residential	**$ 401**	$ 386	**$ 834**	$ 822
Light industrial and commercial	**460**	467	**927**	897
Large industrial	**219**	197	**411**	379
Other sales	**200**	170	**280**	253
Total Domestic Revenue Before Regulatory Transfers	**1,280**	1,220	**2,452**	2,351
Regulatory transfers	**6**	8	**124**	106
Total Domestic	**1,286**	1,228	**2,576**	2,457
Total Trade	**256**	153	**487**	389
Total Revenue	**$ 1,542**	$ 1,381	**$ 3,063**	$ 2,846

NOTE 4: OPERATING EXPENSES

(in millions)	*For the three months ended September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Electricity and gas purchases	**$ 564**	$ 444	**$ 1,048**	$ 902
Water rentals	**82**	80	**163**	159
Transmission charges	**44**	46	**86**	89
Personnel expenses	**131**	126	**287**	270
Materials and external services	**145**	146	**290**	300
Amortization and depreciation (Note 6)	**319**	300	**638**	600
Grants, taxes and other costs	**80**	80	**158**	157
Less: Capitalized costs	**(35)**	(40)	**(70)**	(80)
	$ 1,330	$ 1,182	**$ 2,600**	$ 2,397

NOTE 5: FINANCE CHARGES

(in millions)	*For the three months ended September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Interest on long-term debt	**$ 223**	$ 208	**$ 438**	$ 408
Interest on finance lease liabilities	**10**	11	**21**	22
Less: Other recoveries	**(17)**	(20)	**(34)**	(41)
Capitalized interest	**(38)**	(32)	**(76)**	(64)
	$ 178	$ 167	**$ 349**	$ 325

NOTE 6: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Depreciation of property, plant and equipment	**$ 194**	$ 187	**$ 388**	$ 373
Amortization of intangible assets	**21**	21	**42**	42
Amortization of regulatory accounts (Note 9)	**104**	92	**208**	185
	$ 319	$ 300	**$ 638**	$ 600

NOTE 7: INVENTORIES

(in millions)	***As at September 30*** **2018**	*As at March 31* 2018
Materials and supplies	**$ 151**	$ 142
Natural gas trading inventories	**53**	2
	$ 204	$ 144

No natural gas trading inventories are pledged as security for liabilities.

NOTE 8: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures, before contributions in aid of construction, for the three and six months ended September 30, 2018 were $1,985 million and $2,524 million, respectively (2017 - $559 million and $1,135 million, respectively).

On August 1, 2017, BC Hydro agreed to exercise its option to purchase the remaining two-thirds interest of Waneta from Teck Resources (Teck) for $1.2 billion. Following receipt of BCUC approval in July 2018, BC Hydro completed the transaction on July 26, 2018. The transaction has been accounted for as an asset acquisition, with the purchase price being allocated to the applicable integrated components of the property, plant and equipment acquired. The purchase agreement includes a 20 year agreement, whereby BC Hydro has contracted to sell two-thirds of the production of Waneta to Teck. Teck has an option to extend such agreement for a further 10 years.

As of September 30, 2018, the Company has contractual commitments to spend $3,502 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 9: RATE REGULATION

On March 1, 2018, the BCUC issued Order No. G-47-18, which approved final rate increases of 4.0 per cent for fiscal 2017, 3.5 per cent for fiscal 2018, and 3.0 per cent for fiscal 2019. In addition, the BCUC directed the establishment of two new regulatory accounts, the Post Employment Benefit Current Pension Costs Regulatory Account and the Dismantling Cost Regulatory Account and the closure of the Future Removal and Site Restoration Regulatory Account.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. In the absence of rate regulation, these amounts would be reflected in total comprehensive income. For the three and six months ended September 30, 2018, the impact of regulatory accounting has resulted in a net decrease to total comprehensive income of $289 million and $301 million respectively (2017 - $132 million and $120 million, respectively). For each regulatory account, the amount reflected in the Net Change column in the following regulatory tables represents the impact on comprehensive income for the applicable year, unless otherwise recovered through rates. 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 SIX MONTHS ENDED SEPTEMBER 30, 2018

(in millions)	*As at April 1 2018*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*As at September 30 2018*
Regulatory Assets						
Non-Heritage Deferral Account[1]	$ 462	$ 5	$ 9	$ (101)	$ (87)	$ 375
Trade Income Deferral Account	127	(108)	-	(19)	(127)	-
Demand-Side Management	903	28	-	(50)	(22)	881
First Nations Provisions & Costs	518	12	2	(20)	(6)	512
Non-Current Pension Costs	304	-	-	(29)	(29)	275
Site C	472	-	9	-	9	481
CIA Amortization	88	(2)	-	-	(2)	86
Environmental Provisions & Costs	261	(4)	(1)	(15)	(20)	241
Smart Metering & Infrastructure	239	-	5	(16)	(11)	228
IFRS Pension	535	-	-	(19)	(19)	516
IFRS Property, Plant & Equipment	1,025	34	-	(14)	20	1,045
Rate Smoothing	815	141	-	-	141	956
Other Regulatory Accounts	142	5	3	(11)	(3)	139
Total Regulatory Assets	5,891	111	27	(294)	(156)	5,735
Regulatory Liabilities						
Heritage Deferral Account[1]	423	95	3	(23)	75	498
Trade Income Deferral Account	-	42	-	9	51	51
Foreign Exchange Gains and Losses	31	-	-	(19)	(19)	12
Debt Management	158	102	-	-	102	260
Total Finance Charges[1]	134	(12)	-	(51)	(63)	71
Other Regulatory Accounts	5	1	-	(2)	(1)	4
Total Regulatory Liabilities	751	228	3	(86)	145	896
Net Regulatory Asset	$ 5,140	$ (117)	$ 24	$ (208)	$ (301)	$ 4,839

[1] As a result of the adoption of IFRS 15, the opening balances as at April 1, 2018 of the Heritage Deferral Account includes an increase of $319 million to the liability balance, the Non-Heritage Deferral Account includes a decrease of $1 million to the asset balance and the Total Finance Charges regulatory account includes a decrease of $5 million to the liability balance, for a total reduction to the net regulatory asset balance of $315 million. Refer to Note 2 for more details.

NOTE 10: OTHER NON-CURRENT ASSETS

(in millions)	***As at September 30* 2018**	*As at March 31* 2018
Non-current receivables	**$ 156**	$ 245
Sinking funds	**186**	182
Other	**264**	256
	$ 606	$ 683

Included in the non-current receivables balance are $132 million of receivables (March 31, 2018 - $191 million) attributable to contributions-in-aid and tariff supplemental charges related to a transmission line and $5 million of receivables (March 31, 2018 - $28 million) from mining customers participating in the Mining Customer Payment Plan that was established in February 2016 as a result of a direction from the Province.

Included in the other balance is long-term portion of prepaid expenses from Site C of $242 million (March 31, 2018 - $229 million).

NOTE 11: LONG-TERM DEBT AND DEBT MANAGEMENT

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

The Company has a commercial paper borrowing program with the Province which is limited to $4,500 million, and is included in revolving borrowings. At September 30, 2018, the outstanding amount under the borrowing program was $2,048 million (March 31, 2018 - $2,053 million).

For the three months ended September 30, 2018, the Company issued bonds for net proceeds of $1,544 million (2017 - $274 million) and a par value of $1,550 million (2017 - $300 million), a weighted average effective interest rate of 2.9 per cent (2017 - 3.3 per cent) and a weighted average term to maturity of 19.0 years (2017 - 30.7 years). For the six months ended September 30, 2018, the Company issued bonds for net proceeds of $2,418 million (2017 - $569 million) and a par value of $2,450 million (2017 - $600 million), a weighted average effective interest rate of 3.0 per cent (2017 - 3.1 per cent) and a weighted average term to maturity of 19.8 years (2017 - 30.9 years).

For the three months ended September 30, 2018, there were no bond maturities (2017 - no bond maturities). For the six months ended September 30, 2018, the Company redeemed bonds with par value of $457 million (2017 - $40 million par value).

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 income, and contributed surplus. The Company monitors its capital structure on the basis of its debt to equity ratio.

During the three and six months ended September 30, 2018, there were no changes in the approach to capital management.

The debt to equity ratio at September 30, 2018, and March 31, 2018 was as follows:

(in millions)		***As at September 30* 2018**		*As at March 31* 2018
Total debt, net of sinking funds	**$**	**22,097**	$	20,182
Less: Cash and cash equivalents		**(172)**		(42)
Net Debt	**$**	**21,925**	$	20,140
Retained earnings	**$**	**5,402**	$	5,347
Contributed surplus		**60**		60
Accumulated other comprehensive income		**60**		49
Total Equity	**$**	**5,522**	$	5,456
Net Debt to Equity Ratio		**80 : 20**		79 : 21

Payment to the Province

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

The fiscal 2018 Payment to the Province was $159 million and was paid in June 2018. As a result, the Payment for fiscal 2019 will be $59 million and the Company has accrued $59 million as at September 30, 2018.

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 and prior to the application of regulatory accounting for the three and six months ended September 30, 2018 was $41 million and $82 million, respectively (2017 - $41 million and $82 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and six months ended September 30, 2018 were $11 million and $22 million (2017 - $10 million and $20 million).

NOTE 14: FINANCIAL INSTRUMENTS

Finance charges, including interest income and expenses, for financial instruments disclosed in this note are prior to the application of regulatory accounting for the three and six months ended September 30, 2018 and 2017 (except where noted).

Classification and Measurement of Financial Instruments

The Company adopted IFRS 9 on April 1, 2018 in accordance with the transitional provisions of the standard. The Company has assessed the classification and measurement of financial assets and financial liabilities under IFRS 9. The original measurement categories under IAS 39 and the new measurement categories under IFRS 9 are summarized in the following table:

	IAS 39	**IFRS 9**
Short-term investments	FVTPL	FVTPL
Derivatives not in a hedging relationship	FVTPL	FVTPL
Cash	Loans and receivables	Amortized cost
Restricted cash	Loans and receivables	Amortized cost
Accounts receivable and other receivables	Loans and receivables	Amortized cost
US dollar sinking funds	Held to maturity	Amortized cost
Accounts payable and accrued liabilities	Other financial liabilities	Amortized cost
Revolving borrowings	Other financial liabilities	Amortized cost
Long-term debt (including current portion due in one year)	Other financial liabilities	Amortized cost
Finance lease obligations, First Nations liabilities and Other liabilities presented in Other long-term liabilities	Other financial liabilities	Amortized cost

There has been no change in the carrying value or fair value of the Company’s financial instruments or to previously reported figures as a result of changes to the measurement categories in the table noted above.

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at September 30, 2018 and March 31, 2018. The fair values of non-derivative financial instruments, where the carrying value differs from fair value, are classified as Level 2 of the fair value hierarchy.

(in millions)	**September 30, 2018 Carrying Value**	**September 30, 2018 Fair Value**	March 31, 2018 Carrying Value	March 31, 2018 Fair Value
Fair Value Through Profit or Loss (FVPTL):				
Cash equivalents - short-term investments	**$ 139**	**$ 139**	$ 31	$ 31
Amortized Cost:				
Cash	**33**	**33**	11	11
Restricted cash	**28**	**28**	77	77
Accounts receivable and accrued revenue	**617**	**617**	733	733
Non-current receivables	**156**	**153**	245	228
Sinking funds	**186**	**200**	182	201
Accounts payable and accrued liabilities	**(1,468)**	**(1,468)**	(1,621)	(1,621)
Revolving borrowings	**(2,048)**	**(2,048)**	(2,053)	(2,053)
Long-term debt (including current portion due in one year)	**(20,235)**	**(22,163)**	(18,311)	(20,814)
First Nations liabilities (non-current portion)	**(397)**	**(586)**	(399)	(652)
Finance lease obligations (non-current portion)	**(648)**	**(648)**	(653)	(653)
Other liabilities	**(419)**	**(424)**	(409)	(416)

The carrying value of cash, cash equivalents, restricted cash, loans and receivables, accounts payable and accrued liabilities, and revolving borrowings approximates fair value due to the short duration of these financial instruments.

Financial Risk Management Overview

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

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under IFRS 7, *Financial Instruments: Disclosures.* However, for a complete understanding of the nature and extent of financial risks the Company is exposed to, this note should be read in conjunction with the Company's discussion of Risk Management found in the Management's Discussion and Analysis section of the 2018 Annual Service Plan Report.

(a) Credit Risk

Credit risk refers to the risk that one party to a financial instrument will cause a financial loss for a counterparty by failing to discharge an obligation. The Company is exposed to credit risk related to cash and cash equivalents, restricted cash, accounts receivable, non-current receivables, sinking fund investments, and derivative instruments. The Company manages financial institution credit risk through a Board-approved treasury risk management policy. Exposures to credit risks are monitored on a regular basis. Our large customers are assessed for credit quality by taking into account external credit ratings, where available, an analysis of financial position and liquidity, past experience and other factors. The Company assigns credit limits for counterparties based on evaluations of their financial condition, net worth, credit ratings, and other credit criteria. For some customers, we may obtain security over accounts receivable in the form of a security deposit. Refer to the Company's annual consolidated financial statements for the year ended March 31, 2018 for other credit risk management procedures and practices under credit risk within the financial instrument note. Maximum credit risk with respect to financial assets is limited to the carrying amount presented on the statement of financial position with the exception of U.S. dollar sinking funds classified as amortized cost and carried on the statement of financial position at $186 million. The maximum credit risk exposure for these U.S. dollar sinking funds as at September 30, 2018 is their fair value of $200 million.

(b) Liquidity Risk

Liquidity risk refers to the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages liquidity risk by forecasting cash flows to identify financing requirements and by maintaining a commercial paper borrowing program under an agreement with the Province (see Note 11). The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province. Cash from operations reduces the Company's liquidity risk. The Company does not believe that it will encounter difficulty in meeting its obligations associated with financial liabilities.

(c) Market Risks

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

(i) Currency Risk

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

The majority of the Company's currency risk arises from long-term debt in the form of U.S. dollar denominated bonds. Energy commodity prices are also subject to currency risk as they are primarily denominated in U.S. dollars. As a result, the Company's trade revenues and purchases of energy commodities, such as electricity and natural gas, and associated accounts receivable and accounts payable, are affected by the Canadian/U.S. dollar exchange rate. In addition, all commodity derivatives and contracts priced in U.S. dollars are also affected by the Canadian/U.S. dollar exchange rate.
The Company actively manages its currency risk through its Treasury Risk Management Policy. The Company uses cross-currency swaps and forward foreign exchange purchase contracts to achieve and maintain foreign currency exposure targets.

(ii) Interest Rate Risk

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

(iii) Commodity Price Risk

The Company is exposed to commodity price risk as fluctuations in electricity prices and natural gas prices could have a materially adverse effect on its financial condition. Prices for electricity and natural gas fluctuate in response to changes in supply and demand, market uncertainty, and other factors beyond the Company's control.

Risk management strategies, policies and limits are designed to ensure the Company's risks and related exposures are aligned with the Company's business objectives and risk tolerance. Powerex enters into commodity derivative contracts to manage commodity price risk. These risks are managed within defined limits that are regularly reviewed by the Board of Directors of Powerex.

Derivative Financial Instruments

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

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

Derivative financial instruments are also used by Powerex to manage economic exposure to market risks relating to commodity prices. Derivatives used for energy trading activities that are not designated as hedges are classified as FVTPL whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. Gains or losses are included in trade revenues.

Hedges

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

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

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

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

The following foreign currency contracts under hedge accounting were in place at September 30, 2018 in a net asset position of $24 million (March 31, 2018 – net asset $99 million). Such contracts are used to hedge the principal on $US denominated long-term debt and the principal and coupon payments on Euro denominated long-term debt for which hedge accounting has been applied. The hedging instruments are effective in offsetting changes in the cash flows of the hedged item attributed to the hedged risk. The main source of hedge ineffectiveness in these hedges is credit risk.

($ amounts in millions)	**September 30, 2018**	March 31, 2018
Cross- Currency Hedging Swaps		
Euro dollar to Canadian dollar - notional amount[1]	**€ 402**	€ 402
Euro dollar to Canadian dollar - weighted average contract rate	**1.47**	1.47
Weighted remaining term	**10 years**	10 years
Foreign Currency Hedging Forwards		
United States dollar to Canadian dollar - notional amount[1]	**$ 573**	$ 773
United States dollar to Canadian dollar - weighted average contract rate	**1.25**	1.19
Weighted remaining term	**12 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)	**September 30, 2018 Fair Value**	March 31, 2018 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contract assets (cash flow hedges for $US denominated long-term debt)	**$ 5**	$ 59
Foreign currency contract liabilities (cash flow hedges for $US denominated long-term debt)	**$ (8)**	$ (8)
Foreign currency contract assets (cash flow hedges for €EURO denominated long-term debt)	**$ 27**	$ 48
	24	99
Non-Designated Derivative Instruments:		
Interest rate contract assets	**143**	180
Interest rate contract liabilities	**(5)**	(97)
Foreign currency contract assets	**-**	6
Commodity derivative assets	**47**	36
Commodity derivatives liabilities	**(46)**	(72)
	139	53
Net asset	**$ 163**	$ 152

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

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

(in millions)	**September 30, 2018**	March 31, 2018
Current portion of derivative financial instrument assets	**$ 66**	$ 174
Current portion of derivative financial instrument liabilities	**(42)**	(112)
Derivative financial instrument assets, non-current	**157**	156
Derivative financial instrument liabilities, non-current	**(18)**	(66)
Net asset	**$ 163**	$ 152

For designated cash flow hedges for the three and six months ended September 30, 2018, a loss of $16 million and $23 million, respectively (2017 – loss of $11 million and a gain of $8 million, respectively) was recognized in other comprehensive income. For the three and six months ended September 30, 2018, $28 million and $34 million, respectively (2017 - $42 million and $46 million, respectively) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains (2017 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $2.7 billion (2017 - $3.9 billion), used to economically hedge the interest rates on future debt issuances, there was a $85 million and $88 million increase, respectively (2017 - $53 million and $72 million increase, respectively) in the fair value of these contracts for the three and six months ended September 30, 2018. For interest rate contracts associated with debt issued, there was a $7 million and $14 million increase, respectively (2017 - $8 million increase and $7 million decrease, respectively) in the fair value of contracts that settled during the three and six months ended September 30, 2018. The net increase for the six months ended September 30, 2018 of $102 million in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a liability balance of $260 million as at September 30, 2018.

For foreign currency contracts not designated as hedges for the three and six months ended September 30, 2018, a loss of $1 million and a gain of $1 million, respectively (2017 – loss of $2 million and $4 million, respectively) was recognized in finance charges with respect to foreign currency contracts for cash management purposes. For foreign currency contracts not designated as hedges, which are comprised primarily of foreign currency contracts for U.S. revolving borrowings, for the three and six months ended September 30, 2018, such contracts had a loss of $1 million and $1 million, respectively (2017 - loss of $35 million and $61 million, respectively) recognized in finance charges. These economic hedges offset $1 million and $1 million, respectively, of foreign exchange revaluation gains (2017 - $36 million and $63 million, respectively) recorded in finance charges with respect to U.S. revolving borrowings for the three and six months ended September 30, 2018.

For commodity derivatives not designated as hedges, a net loss of $4 million and a net gain of $13 million, respectively (2017 - loss of $25 million and $38 million, respectively) was recorded in trade revenue for the three and six months ended September 30, 2018.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)	*For the three months ended September 30* **2018**	2017	*For the six months ended September 30* **2018**	2017
Deferred inception loss, beginning of the period	**$ 20**	$ 26	**$ 22**	$ 36
New transactions	**(10)**	(4)	**(21)**	(8)
Amortization	**4**	(3)	**13**	(8)
Foreign currency translation loss	**-**	(1)	**-**	(2)
Deferred inception loss, end of the period	**$ 14**	$ 18	**$ 14**	$ 18

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.
- Level 3 - inputs are those that are not based on observable market data.

The following tables present the financial instruments measured at fair value for each hierarchy level as at September 30, 2018 and March 31, 2018:

As at September 30, 2018 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 139	$ -	$ -	$ 139
Derivatives designated as hedges	-	32	-	32
Derivatives not designated as hedges	31	151	9	191
	$ 170	$ 183	$ 9	$ 362

As at September 30, 2018 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(36)	(9)	(7)	(52)
	$ (36)	$ (17)	$ (7)	$ (60)

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

As at March 31, 2018 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(62)	(106)	(2)	(170)
	$ (62)	$ (114)	$ (2)	$ (178)

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 energy 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.

During the period, energy derivatives with a carrying amount of $1 million were transferred from Level 2 to Level 1 as the Company now uses published price quotations in an active market.

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 three months ended September 30, 2018 and 2017:

(in millions)		
Balance as at April 1, 2018	**$**	**3**
Net loss recognized		(20)
New transactions		6
Existing transactions settled		13
Balance as at September 30, 2018	**$**	**2**

(in millions)		
Balance as at April 1, 2017	**$**	**37**
Net loss recognized		(34)
New transactions		1
Transfer from Level 3 to Level 2		(7)
Existing transactions settled		18
Balance as at September 30, 2017	**$**	**15**

Level 3 fair values for energy derivatives are determined using inputs that are based on 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.

Powerex holds congestion products and structured power transactions that require the use of unobservable inputs when observable inputs are unavailable. Congestion products are valued using forward spreads at liquid hubs that include adjustments for the value of energy at different locations relative to the liquid hub as well as other adjustments that may impact the valuation. Option pricing models are used when the congestion product is an option. Structured power transactions are valued using standard contracts at a liquid hub with adjustments to account for the quality of the energy, the receipt or delivery location, and delivery flexibility where appropriate. Significant unobservable inputs include adjustments for the quality of the energy and the transaction location relative to the reference standard liquid hub.

During the three and six months ended September 30, 2018, unrealized losses of $11 million and $3 million, respectively (2017 - $4 million and $18 million losses, respectively) were recognized on Level 3 derivative commodity instruments held at September 30, 2018. These losses were recognized in trade revenues.

Methodologies and procedures regarding Powerex's energy trading Level 3 fair value measurements are determined by Powerex's Risk Management group. Level 3 fair values are calculated within Powerex's Risk Management policies for trading activities based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by Powerex's Risk Management and Finance departments on a regular basis.

NOTE 15: OTHER NON-CURRENT LIABILITIES

(in millions)		***As at September 30 2018***		*As at March 31* 2018
Provisions				
Environmental liabilities	**$**	**299**	$	317
Decommissioning obligations		**52**		53
Other		**29**		55
		380		425
First Nations liabilities		**413**		416
Finance lease obligations		**660**		665
Unearned revenue		**206**		577
Other liabilities		**419**		409
		2,078		2,492
Less: Current portion, included in accounts payable and accrued liabilities		**(170)**		(154)
	$	**1,908**	$	2,338

NOTE 16: 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.