British Columbia Hydro and Power Authority

2018/19

THIRD QUARTER REPORT

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three and nine months ended December 31, 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 nine months ended December 31, 2018.

For the periods reported in this MD&A, 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). All financial information is expressed in Canadian dollars unless otherwise specified.

As a result of the Province's Treasury Board issuing BC Reg 231/2018 on November 7, 2018, BC Hydro will be required to prepare its annual fiscal 2019 financial statements in accordance with International Financial Reporting Standards (IFRS) pursuant to Section 23.1 of the Budget Transparency and Accountability Act. Management is currently assessing the impacts of the adoption of IFRS and expects that the adoption of IFRS will not have a material impact on the consolidated financial results; however, it will result in significant financial statement presentation and disclosure differences.

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

- In February 2019, the Province released the Comprehensive Review of BC Hydro: Phase 1 Final Report. The report outlines a number of actions that enhance regulatory oversight of BC Hydro while still enabling the Province to advance social, economic, and environmental priorities. The key outcomes include:
    - The Province has repealed a number of regulations that restricted the BCUC's decision making in the past. Moving forward, this will enable the BCUC to review and make decisions on BC Hydro's costs, proposed rate increases and almost all regulatory accounts, programs, and capital projects.
    - The Province accepted the recommendation that BC Hydro cease using the Rate Smoothing Regulatory Account (RSRA) and write-off the balance in the account in fiscal 2019. BC Hydro expensed the entire $1.04 billion RSRA balance to operating expenses as at December 31, 2018 (see note 9 of the financial statements).

  - The Province has changed the basis of accounting that BC Hydro is required to follow. BC Hydro will fully adopt IFRS, which is in aligned with the requirements of Canadian Generally Accepted Accounting Principles, in its annual fiscal 2019 financial statements. BC Hydro has disclosed this in its third quarter financial statements (see note 2 of the financial statements).

- The net loss for the three months ended December 31, 2018 was $814 million, compared to a net income of $233 million in the same period in the prior fiscal year. The net loss was primarily due to the write-off of the balance in the RSRA of $1.04 billion as discussed above. Excluding the RSRA write-off, the net income for the three months ended December 31, 2018 was $230 million, comparable to the net income in the same period in the prior fiscal year. During the three months ended December 31, 2018, domestic revenues were $68 million higher 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 $21 million higher domestic cost of energy mainly as a result of higher planned purchases from Independent Power Producers, $16 million higher amortization, and $17 million higher personnel expenses.

- The net loss for the nine months ended December 31, 2018 was $700 million, compared to a net income of $357 million in the same period in the prior fiscal year. Excluding the RSRA write-off, the net income for the nine months ended December 31, 2018 was $344 million, $13 million lower compared to the net income in the same period in the prior fiscal year. The decrease was primarily due to higher domestic cost of energy of $70 million mainly as a result of higher planned purchases from Independent Power Producers, $54 million higher amortization and depreciation, $32 million higher finance charges, and $34 million higher personnel expenses. This was partially offset by higher domestic revenues of $187 million primarily due to higher average customer rates reflecting an average rate increase as approved by the BCUC of 3.0 per cent effective April 1, 2018.

- Water inflows to the system during the nine months ended December 31, 2018 were 89 per cent of average compared to 97 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 spring 2018 snowpack in the Peace region.

- Capital expenditures, before contributions in aid of construction, for the three and nine months ended December 31, 2018 were $654 million and $3.18 billion, respectively. BC Hydro continues to invest significantly in capital projects/programs to refurbish its ageing infrastructure, and build and acquire new assets for future growth, including Site C, Waneta 2/3 interest acquisition, Downtown Vancouver Electricity Supply: West End Strategic Property Purchase, John Hart Generating Station Replacement, Distribution Wood Poles Replacements, Peace Region Electricity Supply, and Bridge River 2 Units 5 and 6 Upgrade.

CONSOLIDATED RESULTS OF OPERATIONS

($ in millions)	*For the three months ended December 31* **2018**	2017	Change	*For the nine months ended December 31* **2018**	2017	Change
Total Revenues	**$ 1,845**	$ 1,646	$ 199	**$ 4,908**	$ 4,492	$ 416
Net Income (Loss)	**$ (814)**	$ 233	$ (1,047)	**$ (700)**	$ 357	$ (1,057)
Capital Expenditures	**$ 654**	$ 641	$ 13	**$ 3,178**	$ 1,776	$ 1,402
GWh Sold (Domestic)	**13,995**	14,917	(922)	**39,916**	42,684	(2,768)

($ in millions)	***As at December 31, 2018***	*As at March 31, 2018*	Change
Total Assets	**$ 34,897**	$ 33,742	$ 1,155
Shareholder's Equity	**$ 4,686**	$ 5,456	$ (770)
Accrued Payment to the Province	**$ 59**	$ 159	$ (100)
Retained Earnings	**$ 4,588**	$ 5,347	$ (759)
Debt to Equity	**83 : 17**	79: 21	n/a
Number of Domestic Customer Accounts	**2,041,283**	2,018,044	23,239
Total Reservoir Storage (GWh)	**17,629**	10,877	6,752

REVENUES

For the three and nine months ended December 31, 2018, total revenues, after regulatory account transfers, of $1.85 billion and $4.91 billion, respectively, were $199 million (or 12 per cent) and $416 million (or 9 per cent) higher than same period in the prior fiscal year. The increase over the prior fiscal year for the three months ended December 31, 2018 was due to higher trade revenues of $131 million and higher domestic revenues of $68 million. The increase over the prior fiscal year for the nine months ended December 31, 2018 was due to higher trade revenues and domestic revenues of $229 million and $187 million, respectively. The table below shows revenues before regulatory account transfers, the amount of regulatory account transfers, and total revenues after regulatory account transfers.

for the three months ended December 31	(in millions) 2018	2017	(gigawatt hours) 2018	2017	($ per MWh)[2] 2018	2017
Domestic Revenues						
Residential	**$ 601**	$ 620	**5,040**	5,303	**$ 119.25**	$ 116.91
Light industrial and commercial	**494**	492	**4,854**	4,971	**101.77**	98.97
Large industrial	**223**	210	**3,621**	3,555	**61.59**	59.07
Other sales	**117**	96	**480**	1,088	**-**	-
Total Domestic Revenue Before Regulatory Transfers	**1,435**	1,418	**13,995**	14,917	**102.54**	95.06
Regulatory transfers	**105**	54	**-**	-	**-**	-
Total Domestic Revenues	**$ 1,540**	$ 1,472	**13,995**	14,917	**$ 110.04**	$ 98.68
Trade Revenues						
Gross electricity and gas	**$ 420**	$ 305	**6,191**	8,590	**$ 67.60**	$ 35.31
Less: forward electricity and gas purchases	**(115)**	(131)	**-**	-	**-**	-
Total Trade Revenues[1]	**$ 305**	$ 174	**6,191**	8,590	**$ 49.27**	$ 20.26
Total Revenues	**$ 1,845**	$ 1,646	**20,186**	23,507	**$ 91.40**	$ 70.02

for the nine months ended December 31	(in millions) 2018	2017	(gigawatt hours) 2018	2017	($ per MWh)[2] 2018	2017
Domestic Revenues						
Residential	**$ 1,435**	$ 1,442	**12,271**	12,561	**$ 116.94**	$ 114.80
Light industrial and commercial	**1,421**	1,389	**14,034**	14,091	**101.25**	98.57
Large industrial	**634**	589	**10,400**	10,045	**60.96**	58.64
Other sales	**397**	349	**3,211**	5,987	**-**	-
Total Domestic Revenue Before Regulatory Transfers	**3,887**	3,769	**39,916**	42,684	**97.38**	88.30
Regulatory transfers	**229**	160	**-**	-	**-**	-
Total Domestic Revenues	**$ 4,116**	$ 3,929	**39,916**	42,684	**$ 103.12**	$ 92.05
Trade Revenues						
Gross electricity and gas	**$ 1,073**	$ 965	**19,614**	25,704	**$ 48.97**	$ 34.55
Less: forward electricity and gas purchases	**(281)**	(402)	**-**	-	**-**	-
Total Trade Revenues[1]	**$ 792**	$ 563	**19,614**	25,704	**$ 40.38**	$ 21.90
Total Revenues	**$ 4,908**	$ 4,492	**59,530**	68,388	**$ 82.45**	$ 65.68

[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 December 31, 2018 were $1.54 billion, an increase of $68 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 was also due to higher other sales, which includes revenues related to the sale of two-thirds of the production from the Waneta Dam and Generating Facility. These higher revenues were partially offset by lower surplus sales (a component of other sales), lower residential revenue driven by warmer weather and lower average use per customer account, as well as lower consumption from light industrial and commercial customers.

In addition, there were $51 million higher regulatory account transfers related to the RSRA, Non-Heritage Deferral Account (NHDA), and Heritage Deferral Account (HDA).

Domestic revenues for the nine months ended December 31, 2018 were $4.12 billion, an increase of $187 million (or 5 per cent) compared to the same period in the prior fiscal year. The increase over the same period in the prior fiscal year, before regulatory account transfers, was primarily due to the same factors as described above.

In addition, there were $69 million higher regulatory account transfers related to the RSRA, NHDA, and HDA. 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.

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 December 31, 2018 were $305 million, an increase of $131 million (or 75 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 nine months ended December 31, 2018 were $792 million, an increase of $229 million (or 41 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 nine months ended December 31, 2018, total operating expenses, after regulatory account transfers, of $2.48 billion and $5.08 billion, respectively, were $1.24 billion and $1.44 billion higher than the same period in the prior fiscal year. The increase over the prior fiscal year was primarily related to the write-off of the RSRA. Excluding the RSRA write-off, the total operating expenses for the three and nine months ended December 31, 2018 were $1.44 billion and $4.04 billion respectively, $194 million and $397 million higher compared to the total operating expenses in the same period in the prior fiscal year. The increase for the three months ended December 31, 2018 as compared to the same period in the prior fiscal year was primarily due to higher energy costs of $153 million, higher amortization and depreciation of $16 million, and higher personnel expenses of $17 million. The increase over the same period in the prior fiscal year for the nine months ended December 31, 2018 was primarily due to higher energy costs of $300 million, higher amortization and depreciation of $54 million, and higher personnel expenses of $34 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 December 31, 2018 were $746 million, $153 million (or 26 per cent) higher than the same period in the prior fiscal year. The increase was primarily due to higher trade energy costs of $132 million and higher domestic energy costs of $21 million.

Total energy costs after regulatory transfers for the nine months ended December 31, 2018 were $2.04 billion, $300 million (or 17 per cent) higher than the same period in the prior fiscal year. The increase was primarily due to higher trade energy costs of $230 million and higher domestic energy costs of $70 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 December 31	*(in millions)* **2018**	2017	*(gigawatt hours)* **2018**	2017	*($ per MWh)* [2] **2018**	2017
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 85**	$ 80	**11,237**	13,909	**$ 7.56**	$ 5.75
Purchases from Independent Power Producers	**326**	346	**3,144**	3,400	**103.69**	101.76
Other electricity purchases - Domestic	**41**	0	**586**	9	**69.97**	0.00
Gas and transportation for thermal generation	**2**	2	**50**	33	**40.00**	60.61
Transmission charges and other expenses	**2**	4	**30**	32	**-**	-
Columbia River Treaty Related Agreements	**(17)**	(3)	**-**	-	**-**	-
Allocation from (to) trade energy	**13**	**(19)**	**144**	(881)	**56.97**	25.80
Total Domestic Cost of Energy Before Regulatory Transfers	**452**	410	**15,191**	16,502	**29.75**	24.85
Energy deferral regulatory transfers	**36**	57	**-**	-	**-**	-
Total Domestic Energy Costs	**$ 488**	$ 467	**15,191**	16,502	**$ 32.12**	$ 28.30
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 262**	$ 190	**6,357**	7,734	**$ 42.74**	$ 24.22
Less: forward electricity and gas purchases	**(115)**	(131)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**147**	59	**-**	-	**-**	-
Transmission charges and other expenses	**66**	60	**-**	-	**-**	-
Allocation (to) from domestic energy	**(13)**	19	**(144)**	881	**56.97**	25.80
Total Trade Cost of Energy Before Regulatory Transfers	**200**	138	**6,213**	8,615	**32.19**	16.02
Trade net margin regulatory transfer	**58**	(12)	**-**	-	**-**	-
Total Trade Energy Costs	**$ 258**	$ 126	**6,213**	8,615	**$ 41.53**	$ 14.63
Total Energy Costs	**$ 746**	$ 593	**21,404**	25,117	**$ 34.85**	$ 23.61

[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 nine months ended December 31	*(in millions)* **2018**	2017	*(gigawatt hours)* **2018**	2017	*($ per MWh)* [2] **2018**	2017
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 253**	$ 241	**30,153**	35,202	**$ 8.39**	$ 6.85
Purchases from Independent Power Producers	**1,004**	1,056	**11,720**	11,921	**85.67**	88.58
Other electricity purchases - Domestic	**42**	1	**637**	41	**65.93**	24.39
Gas and transportation for thermal generation	**10**	7	**121**	34	**82.64**	205.88
Transmission charges and other expenses	**10**	12	**77**	79	**-**	-
Columbia River Treaty Related Agreements	**(64)**	(32)	**-**	-	**-**	-
Allocation from (to) trade energy	**24**	(17)	**556**	(796)	**43.62**	22.62
Total Domestic Cost of Energy Before Regulatory Transfers	**1,279**	1,268	**43,264**	46,481	**29.56**	27.28
Energy deferral regulatory transfers	**113**	54	**-**	-	**-**	-
Total Domestic Energy Costs	**$ 1,392**	$ 1,322	**43,264**	46,481	**$ 32.17**	$ 28.44
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 526**	$ 550	**20,292**	24,950	**$ 26.54**	$ 21.79
Less: forward electricity and gas purchases	**(281)**	(402)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**245**	148	**-**	-	**-**	-
Transmission charges and other expenses	**216**	206	**-**	-	**-**	-
Allocation (to) from domestic energy	**(24)**	17	**(556)**	796	**43.62**	22.62
Total Trade Cost of Energy Before Regulatory Transfers	**437**	371	**19,736**	25,746	**22.14**	14.41
Trade net margin regulatory transfer	**214**	50	**-**	-	**-**	-
Total Trade Energy Costs	**$ 651**	$ 421	**19,736**	25,746	**$ 32.99**	$ 16.35
Total Energy Costs	**$ 2,043**	$ 1,743	**63,000**	72,227	**$ 32.43**	$ 24.13

[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 December 31, 2018 were $488 million, $21 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, were driven by higher energy purchases required to meet domestic load requirements resulting from lower water inflows experienced and higher allocation from trade energy due to increased import opportunities at higher prices than the prior fiscal year. The increase in costs was partially offset by higher recoveries from net water releases associated with the Columbia River Treaty related agreements and lower costs from Independent Power Producers largely driven by fewer deliveries from hydro generating Independent Power Producers due to lower inflows.

Domestic energy costs for the nine months ended December 31, 2018 were $1.39 billion, $70 million (or 5 per cent) higher than the same period in the prior fiscal year. The significant variances from the prior fiscal year, before regulatory account transfers, were primarily due to the same factors as described above.

In addition, there were $21 million lower regulatory account transfers for the three months ended, December 31, 2018, and $59 million higher regulatory account transfers for the nine months ended December 31, 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 December 31, 2018 were $200 million, an increase of $62 million (or 45 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 nine months ended December 31, 2018 were $437 million, an increase of $66 million (or 18 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.

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 the nine months ending December 31, 2018 were 89 per cent of average compared to 97 per cent of average in the same period of the prior fiscal year. The lower water inflows compared to the same period in the prior fiscal year were the result of persistent dry weather across the province and significantly below average spring 2018 snowpack in the Peace region.

Total reservoir storage as at December 31, 2018 was 17,629 GWh, a decrease of 1,919 GWh compared to total reservoir storage as at December 31, 2017 of 19,548 GWh. System energy storage dropped below the prior 10-year historical range (19,548 to 24,882 GWh) at the end of Q3 due to below average initial reservoir levels at the start of fiscal 2019, below average inflows across the summer and fall, and strong energy prices resulting in energy exports in July and August.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and nine months ended December 31, 2018 were $157 million and $444 million, respectively, $17 million and $34 million, respectively higher than the corresponding periods in the prior fiscal year primarily due to an increase in the number of full time employees and higher employee benefit costs. The increased number of full time employees was primarily due to BC Hydro's Workforce Optimization program and Accenture repatriation, which replaced 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 nine months ended December 31, 2018 were $153 million and $443 million, respectively, $3 million and $13 million lower than the corresponding periods in the prior fiscal year primarily due to BC Hydro's Workforce Optimization program, which replaced external service providers with full-time employees to reduce costs and deliver on our business objectives. However, this reduction in cost was partially offset by higher costs in other operating areas, such as the increased operating costs related to the remaining two-third interest acquired in Waneta Dam.

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 nine months ended December 31, 2018, amortization and depreciation expense was $330 million and $968 million, $16 million and $54 million higher than the corresponding periods in 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 nine months ended December 31, 2018, the amortization and depreciation expense included $115 million and $323 million respectively (three and nine months ended December 31, 2017 - $107 million and $292 million, respectively) of amortization of regulatory account balances, which is the regulatory mechanism to recover the regulatory account balances in rates.

Rate Smoothing Regulatory Account Write-off

During the three months ended December 31, 2018, BC Hydro determined that the collection of the RSRA was no longer probable. As a result, BC Hydro expensed the entire $1.04 billion RSRA balance at December 31, 2018.

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 nine months ended December 31, 2018 were $86 million and $244 million, respectively, comparable to $79 million and $236 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 nine months ended December 31, 2018 were $34 million and $104 million, respectively, compared to capitalized costs of $38 million and $118 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 nine months ended December 31, 2018 were $177 million and $526 million, respectively, $8 million and $32 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 to fund higher capital expenditures.

REGULATORY TRANSFERS

The Company applies the principles of IFRS combined with ASC 980 to reflect the rate-regulated environment in which the Company operates. These standards allow for the deferral of costs and recoveries that under IFRS would otherwise be included in the determination of total comprehensive income. The deferred amounts are either recovered or refunded in future rates.

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 regulatory accounts, 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 December 31* **2018**	2017	*For the nine months ended December 31* **2018**	2017
Energy Deferral Accounts				
Heritage Deferral Account	$ 54	$ 13	**$ (41)**	$ (48)
Non-Heritage Deferral Account	(74)	(106)	**(69)**	(85)
Trade Income Deferral Account	(58)	9	**(208)**	(50)
	(78)	(84)	**(318)**	(183)
Forecast Variance Accounts				
Total Finance Charges	11	(10)	**23**	(22)
Rate Smoothing	(956)	78	**(815)**	199
Non-Current Pension Costs	-	(125)	**-**	(125)
Debt Management	92	56	**(10)**	(9)
Other	29	18	**34**	33
	(824)	17	**(768)**	76
Capital-Like Accounts				
Demand-Side Management	37	17	**65**	41
IFRS Property, Plant & Equipment	16	22	**50**	67
	53	39	**115**	108
Non-Cash Accounts				
Environmental Provisions & Costs	1	4	**(3)**	(2)
First Nations Provisions & Costs	5	4	**17**	15
Other	0	0	**(3)**	(2)
	6	8	**11**	11
Amortization of regulatory accounts	(115)	(107)	**(323)**	(292)
Interest on regulatory accounts	9	16	**33**	49
Net reduction in regulatory accounts	**$ (949)**	**$ (111)**	**$ (1,250)**	$ (231)

The net regulatory asset balance as at December 31, 2018 was $3.89 billion compared to $5.46 billion 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. Please 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 $949 million and $1.25 billion to the Company's regulatory accounts for the three and nine months ended December 31, 2018, respectively, compared to a net reduction of $111 million and $231 million, respectively, in the same period in the prior fiscal year.

Net reductions to the regulatory accounts during the nine months ended December 31, 2018 included:

- $815 million to the RSRA as BC Hydro determined that collection of the RSRA was no longer probable and therefore BC Hydro expensed the entire balance to operating costs. The operating expense of $1.04 billion recorded during the three and nine months ended December 31, 2018 was comprised of the $815 million balance in the account as at April 1, 2018 and $299 million deferred in the account during the nine-month period ended December 31, 2018 prior to the write-off.

- Net amortization of $323 million. Amortization is the regulatory mechanism to recover the regulatory account balances in rates; and

- $318 million to the energy deferral accounts, primarily due to higher trade net income and lower domestic cost of energy.

These net reductions were partially offset by:

- $65 million of planned additions to the Demand-Side Management Regulatory Account for expenditures incurred to support energy conservation;

- $50 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; and

- Interest on regulatory accounts of $33 million.

BC Hydro has regulatory mechanisms in place to collect 25 of 27 regulatory accounts in use or with balances at December 31, 2018 in rates over various periods, which represent approximately 88 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 net 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 December 31, 2018.

As at December 31, 2018, the Company’s net debt to equity ratio was 83:17, which was higher than the net debt to equity ratio of 80:20 as at September 30, 2018. The higher net debt to equity ratio was primarily due to the write-off of the RSRA balance. The Company is forecasting a net debt to equity ratio of 82:18 by the end of fiscal 2019, and is forecasting a net debt to equity ratio of 80:20 in fiscal 2020. The Company will continue working toward achieving the 60:40 net debt to equity ratio.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the nine months ended December 31, 2018 was $1.14 billion, compared to $1.13 billion 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, offset against higher domestic cost of energy, and higher finance charges.

The long-term debt balance net of sinking funds as at December 31, 2018 was $22.42 billion compared to $20.18 billion as at March 31, 2018. Long-term debt increased primarily to fund capital expenditures, including the acquisition of the two-thirds interest in Waneta, and the increase was mainly a result of an increase in long-term bond issuances for net proceeds of $2.42 billion ($2.45 billion par value), higher revolving borrowings of $1.08 billion and net foreign exchange losses of $40 million. This increase was partially offset by long-term bond redemptions totaling $1.29 billion par value, sinking fund income of $7 million, and amortization of premiums of $5 million.

CAPITAL EXPENDITURES

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

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2018**	2017	**2018**	2017
Transmission lines and substations replacements and expansion	**$ 97**	$ 170	**$ 358**	$ 384
Generation replacements and expansion	**90**	135	**295**	407
Distribution system improvements and expansion	**123**	123	**366**	372
General, including technology, vehicles and buildings	**43**	46	**104**	131
Waneta two-thirds interest acquisition	**-**	-	**1,219**	-
Site C	**301**	167	**836**	482
Total Capital Expenditures	**$ 654**	$ 641	**$ 3,178**	$ 1,776

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 T&D Stations, UBC Load Increase Stage 2, Horne Payne Substation Upgrade, Kamloops Substation, and 138kV Circuit Breaker Replacement.

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

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

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

The Waneta 2/3 interest acquisition is BC Hydro's purchase of Teck Resources Limited.'s (Teck) two-third interest in the Waneta Dam and associated assets for $1.20 billion.

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.

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 November 2018, intervener evidence was filed arguing for a different approach for the BCUC's regulatory oversight of BC Hydro's capital expenditures and projects. In response to the intervener evidence, BC Hydro filed rebuttal evidence in February, 2019. The proceeding will transition to the final argument phase beginning in April 2019.

Supply Chain Applications Project Application

In December 2016, BC Hydro submitted the Supply Chain Applications Project Phase One Application under section 44.2 for acceptance of Project's Definition Phase capital 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 cost is estimated to be between $71 million and $79 million with a planned in service date in the fourth quarter of fiscal 2020.

In September 2018, BC Hydro's Board of Directors authorized the Project to proceed with Implementation Phase activities subject to the final project approval of the BCUC. In October 2018, BC Hydro filed its Phase Two Verification Report (Report) with the BCUC. The Report included an update on the Project's cost, benefits, scope, risks and schedule. BC Hydro filed its Final Argument in the proceeding in January 2019. A decision expected by May 2019.

Mandatory Reliability Standards Reliability Coordinator Registration Filing

In September 2018, BC Hydro submitted an application to the Western Electricity Coordinating Council to register for the Reliability Coordinator function in British Columbia. BC Hydro submitted a supplementary filing to the BCUC in October 2018 in support of its application. A reliability coordinator is required in order to preserve reliability of the electricity grid for compliance with mandatory reliability standards. The existing reliability coordinator has announced that they will no longer provide these services in BC at the end of 2019, and BC Hydro considers itself best positioned to assume this role.

Under the *Utilities Commission Act*, the BCUC has the authority to adopt mandatory reliability standards, and can accept or deny BC Hydro's registration for the Reliability Coordinator function. In November 2018, the BCUC initiated a regulatory timetable to review BC Hydro's application. BC Hydro has requested a decision from the BCUC in time to allow for the Reliability Coordinator function to commence on September 2, 2019.

RISK MANAGEMENT

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

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income (loss) 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.

BC Hydro filed an updated forecast with the Province in January 2019 which is incorporated into the February 2019 Service Plan and forecasts a net loss of $424 million for fiscal 2019 and net income of $712 million for fiscal 2020. The loss for fiscal 2019 is a result of BC Hydro ceasing the use of the RSRA and writing off the balance in the RSRA.

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 forecast for fiscal 2020 assumes average water inflows (100 per cent of average), domestic sales of 53,567 GWh, average market energy prices of US $25.88/MWh, short-term interest rates of 2.37 per cent, and a Canadian to US dollar exchange rate of US $0.7910.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions)	*For the three months ended December 31* **2018**	2017	*For the nine months ended December 31* **2018**	2017
Revenues				
Domestic (Note 3)	**$ 1,540**	$ 1,472	**$ 4,116**	$ 3,929
Trade (Note 3)	**305**	174	**792**	563
	1,845	1,646	**4,908**	4,492
Expenses				
Operating expenses (Note 4)	**2,482**	1,244	**5,082**	3,641
Finance charges (Note 5)	**177**	169	**526**	494
Net Income (Loss)	**(814)**	233	**(700)**	357
OTHER COMPREHENSIVE INCOME (LOSS)				
Items Reclassified Subsequently to Net Income (Loss)				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 14)	**40**	12	**17**	20
Reclassification to income of derivatives designated as cash flow hedges (Note 14)	**(69)**	(17)	**(35)**	29
Foreign currency translation gains (losses)	**7**	-	**7**	(8)
Other Comprehensive Income (Loss)	**(22)**	(5)	**(11)**	41
Total Comprehensive Income (Loss)	**$ (836)**	$ 228	**$ (711)**	$ 398

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)		***As at December 31*** **2018**		*As at March 31* 2018
ASSETS				
Current Assets				
Cash and cash equivalents	**$**	**116**	$	42
Restricted cash		**47**		77
Accounts receivable and accrued revenue		**747**		733
Inventories (Note 7)		**216**		144
Prepaid expenses		**85**		167
Current portion of derivative financial instrument assets (Note 14)		**144**		174
		1,355		1,337
Non-Current Assets				
Property, plant and equipment (Note 8)		**27,575**		25,083
Intangible assets (Note 8)		**575**		591
Regulatory assets (Note 9)		**4,651**		5,892
Derivative financial instrument assets (Note 14)		**122**		156
Other non-current assets (Note 10)		**619**		683
		33,542		32,405
	$	**34,897**	$	33,742
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities	**$**	**1,252**	$	1,621
Current portion of long-term debt (Note 11)		**3,307**		3,344
Current portion of derivative financial instrument liabilities (Note 14)		**89**		112
		4,648		5,077
Non-Current Liabilities				
Long-term debt (Note 11)		**19,311**		17,020
Regulatory liabilities (Note 9)		**761**		437
Derivative financial instrument liabilities (Note 14)		**44**		66
Contributions in aid of construction		**1,974**		1,874
Post-employment benefits (Note 13)		**1,503**		1,474
Other non-current liabilities (Note 15)		**1,970**		2,338
		25,563		23,209
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**4,588**		5,347
Accumulated other comprehensive income		**38**		49
		4,686		5,456
	$	**34,897**	$	33,742

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized 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)	49	41	-	357	398
Balance as at December 31, 2017	$ 75	$ (7)	$ 68	$ 60	$ 5,020	$ 5,148
Balance as at April 1, 2018	$ 78	$ (29)	$ 49	$ 60	$ 5,347	$ 5,456
Payment to the Province (Note 12)	-	-	-	-	(59)	(59)
Comprehensive Income (Loss)	7	(18)	(11)	-	(700)	(711)
Balance as at December 31, 2018	$ 85	$ (47)	$ 38	$ 60	$ 4,588	$ 4,686

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the nine months ended December 31* **2018**	2017
Operating Activities		
Net income (loss)	**$ (700)**	$ 357
Regulatory account transfers (Note 9)	**927**	(61)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Notes 6 and 9)	**323**	292
Amortization and depreciation expense (Note 6)	**645**	622
Unrealized (gains) losses on mark-to-market of financial instruments	**(63)**	27
Employee benefit plan expenses	**78**	79
Interest accrual	**642**	595
Other items	**(6)**	76
	1,846	1,987
Changes in:		
Restricted cash	**30**	(16)
Accounts receivable and accrued revenue	**36**	50
Prepaid expenses	**65**	66
Inventories	**(68)**	(8)
Accounts payable, accrued liabilities and other non-current liabilities	**(125)**	(327)
Contributions in aid of construction	**113**	93
Other non-current assets	**4**	(9)
	55	(151)
Interest paid	**(757)**	(708)
Cash provided by operating activities	**1,144**	1,128
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(3,201)**	(1,610)
Cash used in investing activities	**(3,201)**	(1,610)
Financing Activities		
Long-term debt:		
Issued (Note 11)	**2,418**	1,156
Retired (Note 11)	**(1,287)**	(40)
Receipt of revolving borrowings	**6,806**	6,481
Repayment of revolving borrowings	**(5,733)**	(7,159)
Payment to the Province (Note 12)	**(159)**	-
Other items	**86**	66
Cash provided by financing activities	**2,131**	504
Increase in cash and cash equivalents	**74**	22
Cash and cash equivalents, beginning of period	**42**	49
Cash and cash equivalents, end of period	**$ 116**	$ 71

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

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown Corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

The 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 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*, which is consistent with the accounting policies applied in BC Hydro's March 31, 2018 financial statements. 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 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 February 15, 2019.

As a result of the Province's Treasury Board issuing BC Reg 231/2018 on November 7, 2018, BC Hydro will be required to prepare its annual fiscal 2019 financial statements in accordance with International Financial Reporting Standards (IFRS) pursuant to Section 23.1 of the Budget Transparency and Accountability Act. Management is currently assessing the impacts of the adoption of IFRS and expects that the adoption of IFRS will not have a material impact on the consolidated financial results; however, it will result in significant financial statement presentation and disclosure differences.

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 revenue. 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.

Please refer to the "Impact of Changes in Accounting Policies" table 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 nine month periods ended December 31, 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. Please refer to Note 14 for the effect on the Condensed Consolidated Statement of Comprehensive Income for the three month and nine month periods ended December 31, 2018.

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

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2018

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.

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2018**	2017	**2018**	2017
Domestic				
Residential	**$ 601**	$ 620	**$ 1,435**	$ 1,442
Light industrial and commercial	**494**	492	**1,421**	1,389
Large industrial	**223**	210	**634**	589
Other sales	**117**	96	**397**	349
Total Domestic Revenue Before Regulatory Transfers	**1,435**	1,418	**3,887**	3,769
Regulatory transfers	**105**	54	**229**	160
Total Domestic	**1,540**	1,472	**4,116**	3,929
Total Trade	**305**	174	**792**	563
Total Revenue	**$ 1,845**	$ 1,646	**$ 4,908**	$ 4,492

NOTE 4: OPERATING EXPENSES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2018**	2017	**2018**	2017
Electricity and gas purchases	**$ 622**	$ 472	**$ 1,670**	$ 1,374
Water rentals	**82**	79	**245**	238
Transmission charges	**42**	42	**128**	131
Personnel expenses	**157**	140	**444**	410
Materials and external services	**153**	156	**443**	456
Amortization and depreciation (Note 6)	**330**	314	**968**	914
Grants, taxes and other costs	**86**	79	**244**	236
Regulatory account write-off (Note 9)	**1,044**	-	**1,044**	-
Less: Capitalized costs	**(34)**	(38)	**(104)**	(118)
	$ 2,482	$ 1,244	**$ 5,082**	$ 3,641

NOTE 5: FINANCE CHARGES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2018**	2017	**2018**	2017
Interest on long-term debt	**$ 222**	$ 210	**$ 660**	$ 618
Interest on finance lease liabilities	**11**	12	**32**	34
Less: Other recoveries	**(18)**	(20)	**(52)**	(61)
Capitalized interest	**(38)**	(33)	**(114)**	(97)
	$ 177	$ 169	**$ 526**	$ 494

NOTE 6: AMORTIZATION AND DEPRECIATION

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2018**	2017	**2018**	2017
Depreciation of property, plant and equipment	**$ 194**	$ 186	**$ 582**	$ 559
Amortization of intangible assets	**21**	21	**63**	63
Amortization of regulatory accounts (Note 9)	**115**	107	**323**	292
	$ 330	$ 314	**$ 968**	$ 914

NOTE 7: INVENTORIES

(in millions)	***As at December 31*** **2018**	*As at March 31* 2018
Materials and supplies	**$ 160**	$ 142
Natural gas trading inventories	**56**	2
	$ 216	$ 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 nine months ended December 31, 2018 were $654 million and $3.18 billion, respectively (2017 - $641 million and $1.78 billion, 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 $1.20 billion. Following receipt of BCUC approval in July 2018, BC Hydro completed the transaction on July 26, 2018. The transaction has been accounted for as an asset acquisition, with the purchase price being allocated to the applicable integrated components of the property, plant and equipment acquired. The purchase agreement includes a 20 year agreement, whereby BC Hydro has contracted to sell two-thirds of the generation of Waneta to Teck. Teck has an option to extend such agreement for a further 10 years.

As of December 31, 2018, the Company has contractual commitments to spend $3.35 billion 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 nine months ended December 31, 2018, the impact of regulatory accounting has resulted in a net decrease to comprehensive income of $949 million and $1.25 billion respectively (2017 - a net decrease to comprehensive income of $111 million and $231 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 NINE MONTHS ENDED DECEMBER 31, 2018

(in millions)	*As at April 1 2018*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*As at December 31 2018*
Regulatory Assets						
Non-Heritage Deferral Account[1]	$ 462	$ (69)	$ 11	$ (162)	$ (220)	$ 242
Trade Income Deferral Account	127	(109)	1	(19)	(127)	-
Demand-Side Management	903	65	-	(75)	(10)	893
First Nations Provisions & Costs	518	17	3	(30)	(10)	508
Foreign Exchange Gains and Losses	-	1	-	3	4	4
Non-Current Pension Costs	304	-	-	(43)	(43)	261
Site C	472	-	14	-	14	486
CIA Amortization	88	(4)	-	-	(4)	84
Environmental Provisions & Costs	261	(3)	(2)	(23)	(28)	233
Smart Metering & Infrastructure	239	-	7	(23)	(16)	223
IFRS Pension	535	-	-	(29)	(29)	506
IFRS Property, Plant & Equipment	1,025	50	-	(21)	29	1,054
Rate Smoothing[2]	815	(815)	-	-	(815)	-
Other Regulatory Accounts	142	26	4	(15)	15	157
Total Regulatory Assets	5,891	(841)	38	(437)	(1,240)	4,651
Regulatory Liabilities						
Heritage Deferral Account[1]	423	41	4	(36)	9	432
Trade Income Deferral Account	-	99	1	26	126	126
Foreign Exchange Gains and Losses	31	(5)	-	(26)	(31)	-
Debt Management	158	10	-	-	10	168
Total Finance Charges[1]	134	(23)	-	(76)	(99)	35
Other Regulatory Accounts	5	(3)	-	(2)	(5)	-
Total Regulatory Liabilities	751	119	5	(114)	10	761
Net Regulatory Asset	$ 5,140	$ (960)	$ 33	$ (323)	$ (1,250)	$ 3,890

[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.

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

NOTE 10: OTHER NON-CURRENT ASSETS

(in millions)		***As at December 31* 2018**		*As at March 31* 2018
Non-current receivables	**$**	**155**	$	245
Sinking funds		**199**		182
Other		**265**		256
	$	**619**	$	683

Included in the non-current receivables balance are $133 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 the long-term portion of prepaid expenses related to Site C of $249 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 $4.50 billion, and is included in revolving borrowings. At December 31, 2018, the outstanding amount under the borrowing program was $3.13 billion (March 31, 2018 - $2.05 billion).

For the three months ended December 31, 2018, the Company did not issue any bonds (2017 - net proceeds of $587 million, a par value of $600 million, a weighted average effective interest rate of 2.8 per cent, and a weight average term to maturity 9.7 years). For the nine months ended December 31, 2018, the Company issued bonds for net proceeds of $2.42 billion (2017 - $1.16 billion) and a par value of $2.45 billion (2017 - $1.20 billion), a weighted average effective interest rate of 3.0 per cent (2017 - 2.9 per cent) and a weighted average term to maturity of 19.8 years (2017 - 20.3 years).

For the three months ended December 31, 2018, the Company redeemed bonds with a par value of $830 million (2017 - no bond maturities). For the nine months ended December 31, 2018, the Company redeemed bonds with a par value of $1.29 billion (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 nine months ended December 31, 2018, there were no changes in the approach to capital management.

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

(in millions)	***As at December 31*** **2018**	*As at March 31* 2018
Total debt, net of sinking funds	**$ 22,419**	$ 20,182
Less: Cash and cash equivalents	**(116)**	(42)
Net Debt	**$ 22,303**	$ 20,140
Retained earnings	**$ 4,591**	$ 5,347
Contributed surplus	**60**	60
Accumulated other comprehensive income	**38**	49
Total Equity	**$ 4,689**	$ 5,456
Net Debt to Equity Ratio	**83 : 17**	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 December 31, 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 nine months ended December 31, 2018 was $41 million and $124 million, respectively (2017 - $41 million and $122 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2018 were $11 million and $32 million (2017 - $10 million and $30 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 nine months ended December 31, 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 December 31, 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)	**December 31, 2018** Carrying Value	Fair Value	March 31, 2018 Carrying Value	Fair Value
Fair Value Through Profit or Loss (FVPTL):				
Cash equivalents - short-term investments	**$ 116**	**$ 116**	$ 31	$ 31
Amortized Cost:				
Cash	**-**	**-**	11	11
Restricted cash	**47**	**47**	77	77
Accounts receivable and accrued revenue	**747**	**747**	733	733
Non-current receivables	**155**	**153**	245	228
Sinking funds	**199**	**216**	182	201
Accounts payable and accrued liabilities	**(1,252)**	**(1,252)**	(1,621)	(1,621)
Revolving borrowings	**(3,131)**	**(3,131)**	(2,053)	(2,053)
Long-term debt (including current portion due in one year)	**(19,487)**	**(21,519)**	(18,311)	(20,814)
First Nations liabilities (non-current portion)	**(387)**	**(513)**	(399)	(652)
Finance lease obligations (non-current portion)	**(644)**	**(644)**	(653)	(653)
Other liabilities	**(431)**	**(438)**	(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 $199 million. The maximum credit risk exposure for these U.S. dollar sinking funds as at December 31, 2018 is their fair value of $216 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 December 31, 2018 in a net asset position of $63 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)	**December 31, 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	**9 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	**11 years**	9 years

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

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

(in millions)	**December 31, 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 $US denominated long-term debt)	**$ 25**	$ 59
Foreign currency contract liabilities (cash flow hedges for $US denominated long-term debt)	**-**	(8)
Foreign currency contract assets (cash flow hedges for €EURO denominated long-term debt)	**38**	48
	63	99
Non-Designated Derivative Instruments:		
Interest rate contract assets	**85**	180
Interest rate contract liabilities	**(39)**	(97)
Foreign currency contract assets	**16**	6
Commodity derivative assets	**102**	36
Commodity derivatives liabilities	**(94)**	(72)
	70	53
Net asset	**$ 133**	$ 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)	**December 31, 2018**	March 31, 2018
Current portion of derivative financial instrument assets	**$ 144**	$ 174
Current portion of derivative financial instrument liabilities	**(89)**	(112)
Derivative financial instrument assets, non-current	**122**	156
Derivative financial instrument liabilities, non-current	**(44)**	(66)
Net asset	**$ 133**	$ 152

For designated cash flow hedges for the three and nine months ended December 31, 2018, a gain of $40 million and $17 million, respectively (2017 – gain of $12 million and $20 million, respectively) was recognized in other comprehensive income. For the three and nine months ended December 31, 2018, $69 million and $35 million, respectively (2017 - $17 million and $29 million, respectively) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses on the underlying hedged item (2017 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $3.40 billion (2017 - $3.90 billion), used to economically hedge the interest rates on future debt issuances, there was a $92 million and $4 million decrease, respectively (2017 - $56 million and $3 million decrease, respectively) in the fair value of these contracts for the three and nine months ended December 31, 2018. For interest rate contracts associated with debt issued, there was a $nil and $14 million increase, respectively (2017 - $nil and $12 million increase, respectively) in the fair value of contracts that settled during the three and nine months ended December 31, 2018. The net increase for the nine months ended December 31, 2018 of $10 million in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a liability balance of $168 million as at December 31, 2018.

For foreign currency contracts not designated as hedges for the three and nine months ended December 31, 2018, a gain of $1 million and $2 million, respectively (2017 – gain of $1 million and loss of $3 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 nine months ended December 31, 2018, such contracts had a gain of $16 million and $15 million, respectively (2017 - gain of $6 million and loss of $55 million, respectively) recognized in finance charges. These economic hedges offset $15 million and $14 million, respectively, of foreign exchange revaluation losses (2017 – loss of $5 million and gain of $58 million, respectively) recorded in finance charges with respect to U.S. revolving borrowings for the three and nine months ended December 31, 2018.

For commodity derivatives not designated as hedges, a net gain of $21 million and $34 million, respectively (2017 - loss of $9 million and $47 million, respectively) was recorded in trade revenue for the three and nine months ended December 31, 2018.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2018**	2017	**2018**	2017
Deferred inception loss, beginning of the period	**$ 14**	$ 18	**$ 22**	$ 36
New transactions	**(14)**	9	**(35)**	1
Amortization	**9**	3	**22**	(5)
Foreign currency translation loss	**-**	-	**-**	(2)
Deferred inception loss, end of the period	**$ 9**	$ 30	**$ 9**	$ 30

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 December 31, 2018 and March 31, 2018:

As at December 31, 2018 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 116	$ -	$ -	$ 116
Derivatives designated as hedges	-	63	-	63
Derivatives not designated as hedges	71	124	8	203
	$ 187	$ 187	$ 8	$ 382

As at December 31, 2018 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ -	$ -	$ -
Derivatives not designated as hedges	(64)	(51)	(18)	(133)
	$ (64)	$ (51)	$ (18)	$ (133)

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 December 31, 2018 and 2017:

(in millions)		
Balance as at April 1, 2018	**$**	**3**
Net loss recognized		(36)
New transactions		9
Existing transactions settled		14
Balance as at December 31, 2018	**$**	**(10)**

(in millions)		
Balance as at April 1, 2017	**$**	**37**
Net loss recognized		(37)
New transactions		3
Transfer from Level 3 to Level 2		(7)
Existing transactions settled		12
Balance as at December 31, 2017	**$**	**8**

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 nine months ended December 31, 2018, unrealized losses of $14 million and $17 million, respectively (2017 - $3 million and $19 million losses, respectively) were recognized on Level 3 derivative commodity instruments held at December 31, 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 December 31 2018***	*As at March 31* 2018
Provisions		
Environmental liabilities	**$ 289**	$ 317
Decommissioning obligations	**53**	53
Other	**43**	70
	385	440
First Nations liabilities	**402**	401
Finance lease obligations	**657**	665
Unearned revenue	**236**	577
Other liabilities	**431**	409
	2,111	2,492
Less: Current portion, included in accounts payable and accrued liabilities	**(141)**	(154)
	$ 1,970	$ 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.