Report on

NELSON HYDRO

2017 Actual Rural Cost of Service Study

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Executive Summary

The Cost of Service analysis for the Nelson Hydro has been prepared to determine the extent to which all customers are paying an equitable share of costs. This analysis is also informative as to whether Rural customers are fully covering their costs consistent with the cost-of-service concept built into ratemaking by the rate regulator overseeing rural service rates, the British Columbia Utilities Commission (BCUC).

The Nelson Hydro Cost of Service analysis shows that Residential Urban customers and Commercial Rural customers RCC ratios are within a 90%-110% zone of reasonableness, and that Commercial Urban customers are above this range, while Residential Rural are below the range. 2017 Cost of Service outcomes are illustrated in table below.

	2017 COS Allocation	2017 Actual Revenues	RCC Ratio	Compare 90%-110% Range
	$000	$000	%	
Residential - Urban	$4,683	$4,939	105.5%	within
Residential - Rural	$8,161	$6,258	76.7%	low
Commercial - Urban	$4,164	$5,801	139.3%	high
Commercial - Rural	$1,213	$1,255	103.4%	within

Consistent with normal regulatory principles and fair rate of return, Nelson Hydro will need to adjust and should adopt rate increases for the Rural Residential class to achieve a fair rate level to bring the class RCC within the range of reasonableness, including return to the shareholder. This rate adjustments could be done over time to avoid larger bill impacts to the customers.

The following table sets out the components of the costs to serve each of the customer classes. As the table illustrates, the main differences in the costs to serve Urban versus Rural customers is the allocation of Transmission/Distribution (rural must support more investment in wires) and in the allocation of Generation and Power Purchase costs (urban customers benefit from the allocation of hydraulic generation, with only a portion of their load served by higher cost purchases, rural customers are entirely served by power purchases).

	Average Cost per kW.h sales		Average Cost per kW.h sales	
	Residential - Urban	**Residential - Rural**	**Commercial - Urban**	**Commercial - Rural**
2017 COS Average Cost per kW.h sales - cents/kW.h				
Hydro Generation				
Demand related	0.5	0.0	0.5	0.0
Energy related	2.1	0.0	2.1	0.0
Power Purchases				
Demand related	1.1	3.0	0.9	2.6
Energy related	0.7	4.5	0.7	4.5
Transmission/Distribution				
Demand related	2.5	3.6	2.3	3.4
Customer related	1.2	1.2	0.3	0.7
General				
Demand related	1.1	0.9	1.0	0.8
Energy related	0.5	0.4	0.5	0.4
Customer related	0.5	0.4	0.1	0.1
Total COS	**10.3**	**13.9**	**8.5**	**12.5**
Average cents/kW.h based on 2017 Actual Revenues	**11.0**	**10.6**	**11.8**	**13.0**
Actual over COS, cents/kW.h	0.8	-3.3	3.3	0.5
Actual over COS, %	7%	-24%	39%	4%

The analysis show that under the current rates the Rural area customers are effectively paying no net return to Nelson, and is in fact facing a net deficit of revenue compared to allocated costs yielding a negative 1.5% effective Return on Equity, as shown in the table below.

	Urban	Rural	Total
Net Book Value	24,542	12,577	37,119
Working Capital	916	698	1,614
Mid-Year Rate Base	**25,458**	**13,275**	**38,733**
Mid-Year Long-term Debt	4,030	2,065	6,096
Equity Portion of Rate Base	**21,428**	**11,210**	**32,638**
Rate Revenues	**10,808**	**7,545**	**18,354**
O&M Expenses - direct allocation	2,242	1,322	3,564
share	*63%*	*37%*	
Power Purchase Costs	1,675	5,150	6,825
share	*25%*	*75%*	
O&M Expenses - share of common	1,571	1,158	2,729
share	*58%*	*42%*	
Interest Expense	164	84	248
Total Expenses	**5,651**	**7,714**	**13,365**
ROE		-169	
ROE %		-1.5%	

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1.0 INTRODUCTION AND OVERVIEW

1.1 INTRODUCTION

Nelson Hydro requires Cost of Service ("COS") analysis to determine the cost allocation, and appropriate rates for its customers [including rates for Rural customers, which are regulated by the BCUC; and rates for Urban customers which are approved by the City of Nelson Council], to a degree of complexity commensurate with its status as a small, integrated and regional energy provider.

Nelson Hydro's service area structure reflects separate loads for Urban (within the City of Nelson) versus Rural (outside the City boundaries) service areas. Some costs incurred are directly related to Urban versus Rural service, however, some costs cannot be distinguished 100% to Urban versus Rural service and therefore considered as common costs.

The 2017 COS is intended to reflect industry-standard considerations for a regulated utility. The COS is based on actual data for 2017, and attempts to address the typical utility rate concepts of a "rate base" to fully reflect depreciation accounting.

1.2 OVERVIEW OF THE NELSON HYDRO[1]

Nelson Hydro is a department of City of Nelson ("City") which provides electrical service to the residents and businesses of City ("Urban" customers) and surrounding areas ("Rural" customers). The City of Nelson through Nelson Hydro owns and operates a 16

[1] http://www.nelson.ca/218/Electrical-Services-Nelson-Hydro [accessed on September 17, 2018].

MW hydroelectric generation facility located at Bonnington Falls on the Kootenay River 16 km southwest of City of Nelson, with a winter output at peak times closer to 9 MW. Nelson Hydro also owns and operates approximately 20 km of 63 kV transmission line that links the plant and supply points from FortisBC to substation facilities in the City of Nelson. The power supply sources for the utility include own-source hydroelectric generation and bulk power purchased from FortisBC at wholesale rates, which is then supplied to Urban and Rural customers through Nelson Hydro owned distribution systems. A small percentage of the hydro output is sold off-system generating modest revenues to help offset system costs.

1.3 RATE SETTING AND BCUC RATE REVIEWS

The City of Nelson Council has an authority to approve the rates for the Urban area customers, while the British Columbia Utilities Commission (BCUC) overseas the rates for Rural area customers, i.e., customers outside of the City boundaries.

The BCUC in its Order G-124-18[2] from August 13, 2018 stated that:

> Nelson Hydro is owned and operated by the City of Nelson and is exempt from regulation under the *Utilities Commission Act* to the extent it is serving customers within its municipal boundaries. Accordingly, while the requested rate increase will be applied uniformly to all ratepayers receiving service both inside and outside the City of Nelson's municipal boundaries, the BCUC's review of the Application pertains solely to Nelson Hydro's non-municipal, or rural, ratepayers.

[2] https://www.bcuc.com/Documents/Proceedings/2018/DOC_52014_2018-07-11_Order_G-124-18.pdf [accessed on September 17, 2018].

During the review of Nelson Hydro's 2018 Rate Application, the BCUC highlighted the following key issues, which are reviewed by the BCUC as part of the application:

i) the calculation of the City's "allowed return" on utility assets, including the dividend payment;

ii) the appropriateness and valuation of the Water License Reserve payment;

iii) the amount transferred annually to the Capital Reserve Fund.

Allowed Return

During the review of the 2017 Rate Application, the BCUC in its Order G-119-17 highlighted that for utilities operating under a traditional cost of service regulatory model the calculation of an allowed return is typically based on the following simple formula: Equity Percentage x Rate Base x ROE = Allowed Return. And as an example, the BCUC used Fortis BC's deemed debt to equity structure of 60 percent debt and 40 percent equity. Nelson Hydro, however, argued that it is not practical for Nelson Hydro to use debt/equity structure in the same way as an investor owned utilities. BCUC in its Order G-124-18 highlighted the fact that as a municipal government department, Nelson Hydro financing differs from investor owned utilities.

In this report, the ROE calculations are based on a normal cost of service regulatory model that uses a rate base, and equity and debt ratios [based on 2017 actuals].

Water License Reserve payment

The BCUC review of Nelson Hydro's 2017 Rate Application also had raised issues regarding water license reserve transfers. During the review of the 2018 Rate Application, the BCUC accepted the argument from Nelson Hydro that water license reserve transfer is a compensation from the BC Government and BC Hydro to the City and should be part of the Nelson Hydro's revenue requirement. As submitted by Nelson Hydro the water license reserve transfer is part of the Urban area revenue requirement and does not impact Rural service area revenue requirement calculation.

Water License Reserve transfers to the City of Nelson are not allocated to the Rural service area.

Capital Reserve Fund transfer

In the Order G-124-18, the BCUC stated it "previously found in the 2017 Decision that Nelson Hydro's practice of financing its capital expenditures primarily through the use and management of the capital reserve fund is reasonable in light of the restrictions on Nelson Hydro's ability to obtain debt financing and the fact that it follows municipal accounting standards which allow for the use of such funds."

It is understood that the use of a capital reserve is a policy approach that Nelson City Council uses for all of its utilities, water, sewer and Nelson Hydro.[3]

1.4 CUSTOMER CLASSES AND CURRENT RATES[4]

Nelson Hydro maintains three types of customer classes - residential, commercial and streetlighting. These customer classes are further broken down into Urban and Rural customer types. The system benefits from the simplicity of having no large industrial,

[3] See City of Nelson 2017 Annual Report, note 14 https://www.nelson.ca/ArchiveCenter/ViewFile/Item/150.
[4] http://www.nelson.ca/231/Electrical-Rates [accessed on September 17, 2018].

wholesale or other customer class with vastly different usage characteristics than the average customer.

The current rates are effective April 1, 2018[5] with across-the-board increase of 2.25% over April 1, 2017 rates. The current rates for residential customers are at the same level for Urban and Rural, while rates for commercial customers in the Rural area are slightly higher than the rates for Urban area (about 3% higher) and streetlight rates for Rural area are higher by about 10%. Table 1 below provides current rates for Urban and Rural customers.

Table 1: Nelson Hydro Rates Effective April 1, 2018[6]

	Unit	Residential		Small Commercial Service with no demand meter, up to 25 kVA		Commercial Service		Streetlight	
		Urban	Rural	Urban	Rural	Urban	Rural	Urban	Rural
Basic charge	$/pay period	15.98	15.98	36.63	37.75	36.63	37.75		
All kWh	cents/kW.h	10.36	10.36	11.80	12.16				
First 15,000	cents/kW.h					10.57	10.90		
Over 15,000	cents/kW.h					10.57	10.90		
Demand charge									
First 20 kW	$/kW	0.00	0.00						
Each additional kW	$/kW	7.26	7.26						
Demand charge (over 25 kVA)	$/kVA					7.76	7.99		
Lamp Size									
150 Watts	$/month							22.51	24.76
250 Watts	$/month							28.21	30.99

[5] BCUC Order G-124-18 dated July 11, 2018 and G-149-18 dated August 13, 2018. Available at http://www.bcuc.com/Documents/Proceedings/2018/DOC_52014_2018-07-11_Order_G-124-18.pdf and https://www.bcuc.com/Documents/Proceedings/2018/DOC_52557_2018-08-13-G-149-18-FinalOrder-Variation.pdf, accessed on September 17, 2018.

[6] Nelson Hydro also offers Flat Service rates which are not included in the table.

2.0 SALES AND GENERATION

The total net system load for 2017 was 174,537 MW.h, including 85,113 MW.h of own source hydro generation (excluding 7,838 MW.h off-system power sales[7]) and 89,424 MW.h of power purchases from Fortis BC. Table 2 below provides summary of total load for 2017.

Table 2: Nelson Hydro Generations and Power Purchases for 2017

	2017 Actual Total
	MW.h
Total Generation and Power Purchases	182,375
Power Sales	7,838
Net Utility Load	174,537
Urban Sales	94,323
Rural Sales	68,752
Losses	11,461
Losses % of sales	7.0%

Table 3 below provides summary of sales by service area and rate class for 2017.

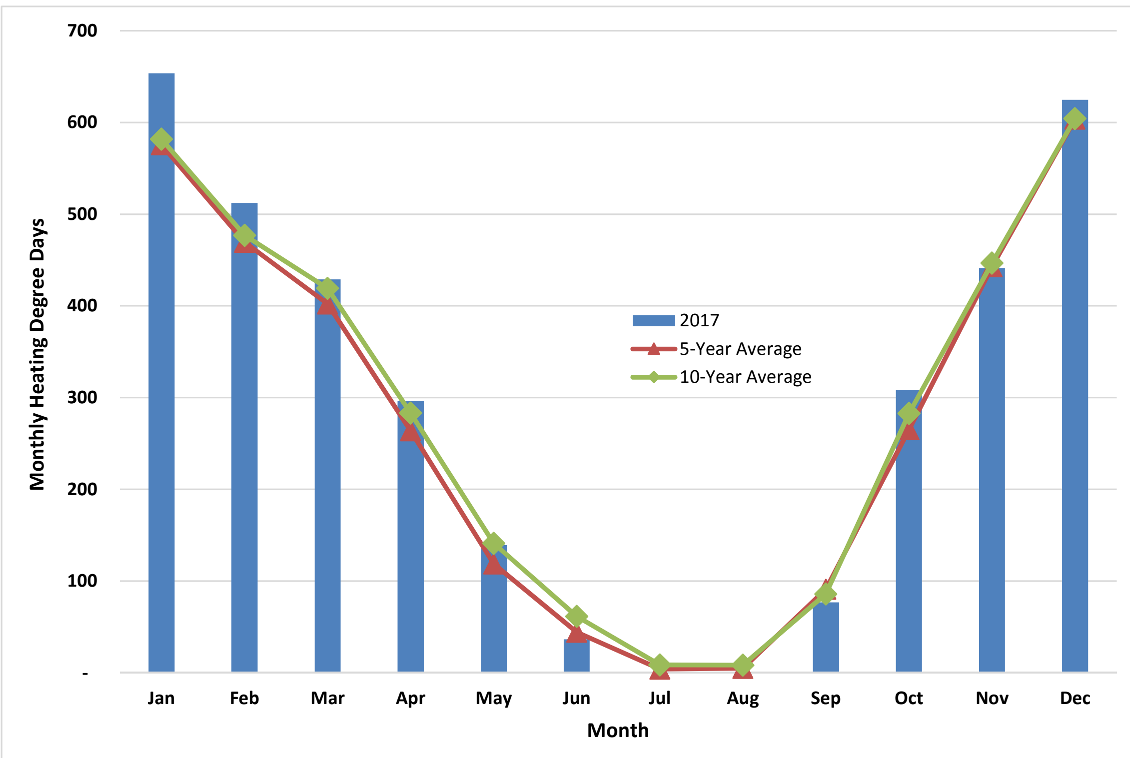
Table 3: Nelson Hydro Sales for 2017

	Urban		Rural		Total	
	Customers	Sales MW.h	Customers	Sales MW.h	Customers	Sales MW.h
Residential	5,133	44,705	4,115	58,814	9,248	103,518
Commercial	917	49,044	319	9,629	1,236	58,673
Streetlight		574		310		884
Total	6,050	94,323	4,434	68,752	10,484	163,076

[7] In most years during the spring freshet Nelson Hydro generates energy for BC Hydro under the Water Rights Agreement, and also for Fortis BC. The tables reflects sales to Fortis BC at about 1.5 GW.h.

The total utility peak for 2017 was in January recorded at 39.7 MW. This is somewhat higher compared to the historical data. This was due to colder than normal weather conditions in December 2016 and January 2017. The Heating Degree Days (HDD) data shows that 2017 January was colder compared to the 5-year and 10-year averages. Figure 1 shows HDD data for City of Nelson for 2017 compared to 5-year and 10-year averages. In a normal weather conditions the peak ranged between 33 MW and 36 MW.

Figure 1: Heating Degree Days for City of Nelson for 2017[8]



[8] The figure is prepared based on HDD information available from Government of Canada weather data. Available at: http://climate.weather.gc.ca/climate_data/daily_data_e.html?hlyRange=1994-02-01%7C2018-09-19&dlyRange=1992-11-01%7C2018-09-18&mlyRange=1992-01-01%7C2006-10-01&StationID=6839&Prov=BC&urlExtension=_e.html&searchType=stnName&optLimit=yearRange&StartYear=2008&EndYear=2018&selRowPerPage=25&Line=5&searchMethod=contains&txtStationName=Nelson&timeframe=2&Day=1&Year=2017&Month=12 [accessed on September 20, 2018]. Heating degree-days for a given day are the number of degrees Celsius that the mean temperature is below 18 C.

3.0 REVENUE REQUIREMENT

A revenue requirement represents the total costs required by the utility to provide service to its customers during a year. A common Canadian regulatory practice is to use a forward-looking or prospective basis for setting the revenue requirement and rates.

Similarly, Nelson Hydro rates for 2018 are set based on forecast costs and revenues for 2018 which was reviewed by the BCUC in light of appropriateness of the proposed increase for rural rates and was approved with 2.25% rate increase effective April 1, 2018 by the BCUC Order G-124-18. [9]

For the purpose of this COS, however, all analysis have been done on the basis of the most recent actuals, 2017, considering availability of the detailed data.[10] There is no reason to expect that use of 2017 actuals would lead to any material problematic or misleading COS output.

The components of the Nelson Hydro's revenue requirement include:

- **Operating and Maintenance ("O&M") expenses:** General annual operations and maintenance expenses. These items would appropriately be included in any revenue requirement calculation. The 2017 Statement of Financial Information for City of Nelson provides O&M expenses for Nelson Hydro at $12.1 million, including $2.2 million for Wages and Benefits, and $9.2 million for Supplies and Services, and $0.7 million Water License Reserve transfers.

[9] BCUC in its Order G-149-18 dated August 13, 2018 directed that $54,000 reduction in dividend payment indicated during the review of 2018 Rate Application, BCUC Order G-124-18, should be applied as a reduction to the rural area costs in 2019 Rate Application.
[10] The actuals are available at account level that provides opportunity to separate into Urban vs Rural.

- **Amortization (or depreciation):** The 2017 Statement of Financial Information for the City of Nelson also shows the annual amortization expenses for each department, including Nelson Hydro. The total amortization expense for 2017 was at $1.031 million.

- **Interest Charges:** Interest is a typical revenue requirement item which are costs related to borrowing for utility needs. Nelson Hydro makes use of relatively small amounts of debt. As a result, 2017 total interest expenses were at $0.248 million.[11]

- **Return on Equity ("ROE"):** As Nelson Hydro is not fully rate regulated utility and does not formally report an ROE, the ROE for 2017 was calculated based on calculated net income (revenues less expenses) divided by the equity portion of the rate base. Consistent with normal regulatory/revenue requirement practice, the dividend payments and annual provisions for reserves (e.g., capital) are not reported separately as a "cost" of the system, but are effectively funded by way of a portion of the net income. As indicated above, the capital reserves are a policy approach of the City of Nelson.

- **Other revenues**, such as revenues from service fees (e.g. connection fee), revenue from power sales to Fortis BC and/or to BC Hydro, and other non-base

[11] As indicated in the previous sections, in its Order G-124-18, the BCUC stated that it "found in the 2017 Decision that Nelson Hydro's practice of financing its capital expenditures primarily through the use and management of the capital reserve fund is reasonable in light of the restrictions on Nelson Hydro's ability to obtain debt financing and the fact that it follows municipal accounting standards which allow for the use of such funds."

rate revenues are included as an offset to revenue requirement. The third party expenses and recoveries are also excluded from the revenue requirement.

The total rate revenues for 2017 calculated at $18.4 million as provided in Table 4 below.

Table 4: Determination of Nelson Hydro's Revenue Requirement for 2017 ($000)[12]

	2017 Actual
Total Revenues	19,473
Less: Revenues from sales to Fortis BC	88
Less: Sale of Services	536
Less: 3rd Party Revenues	161
Less: Investment Income	93
Less: Grants Conditional	242
Rate Revenues/Revenue Requirement	**18,354**
Net O&M Expenses	12,086
Wages and Benefits	*2,173*
Supplies and Services	*9,242*
Adjustments	*13*
Water Licence Reserve Transfer	*658*
Amortization	1,031
Interest charges	248
Total Expenses before ROE	**13,365**
ROE before Capital Reserve Transfer	**4,989**
Capital Reserve Transfer	3,613
ROE after Capital Reserve Transfer	**1,376**

[12] Prepared based on information available from City of Nelson 2017 Statement of Financial Information, https://www.nelson.ca/ArchiveCenter/ViewFile/Item/151 [accessed on September 17, 2018] Note 19. The total O&M expenses also includes $0.087 million loss on disposal of assets. The determination of the revenue requirement also reflects removal of $0.161 million expenses recovered from third parties [removed from both revenue and expenses] as well as adding back $0.174 million expenses which are removed in the consolidated financial statements as these expenses are internal transfers with the City [the expenses include rent payments for the portion of the City building used by Nelson Hydro and payments for share of other City properties] to total net adjustments of $0.013 million. For the purpose of the ROE calculations the transfers to the capital reserve are assumed to be non-expense item and shown separately.

4.0 RATE BASE AND RETURN ON EQUITY

The City of Nelson maintains a normal depreciation-based accounting for capital assets[13]. This data is used to determine a mid-year balance of the capital assets based on original cost, accumulated amortization and a resulting net-book-value.

A rate base also includes provision for working capital. The working capital requirements are calculated based on cash requirements for O&M expenses as well as the mid-year inventory balances[14].

Based on information provided by Nelson Hydro it is estimated that lag days for bill payments for consumed energy would be up to 52 days (15 days consumption lag plus one week billing lag and 30 days to pay the bill) with weighted average of 28 days to pay O&M expenses (wages and benefits every second week, power purchases total of 36 days, including 15 days consumption lag and 21 days to pay the bill, plus 29 days for other supplies and services expenses, based on comparable representative industry values). The net lag days are estimated to be 23.5 days, which leads to approximately a net $0.718 million[15] cash working capital requirement to be included as part of rate base. Inventory balances are approximately $0.895 million, for a total working capital of $1.614 million.

[13] City of Nelson 2017 Statement of Financial Information provides original costs of capital assets along with accumulated amortizations and net book values. Available at https://www.nelson.ca/ArchiveCenter/ViewFile/Item/151 [accessed on September 17, 2018].
[14] The inventory balances are from City of Nelson 2017 Statement of Financial Information, note 13.
[15] Estimated based on total O&M expenses at $11.4 million.

Table 5 provides mid-year balances of capital assets as well as calculated rate base for 2017.

Table 5: Mid-year Balance of Capital Assets and Rate Base ($000)[16]

	2016 Ending Balance	2017 Ending Balance	Mid-year Balance
Generation Plant			
Generating Stations	13,093	13,648	13,371
Substations	7,078	7,132	7,105
Subtotal	**20,172**	**20,780**	**20,476**
Transmission and Distribution Plant			
Transmission	5,900	5,899	5,900
Primary and Secondary Poles & Conduct.	12,013	12,848	12,431
Underground Conduct. & Devices	5,843	5,977	5,910
Transformers	4,657	4,912	4,784
Meters	1,216	1,216	1,216
Streetlight	54	54	54
Other	45	362	204
Subtotal	**29,729**	**31,268**	**30,498**
Total	**49,900**	**52,048**	**50,974**
Accumulated Amortization	**13,458**	**14,251**	**13,855**
Net Book Value	**36,442**	**37,796**	**37,119**
Working Capital Requirements			**1,614**
Total Rate Base			**38,733**

Table 6 below provides estimated ROE for 2017 from Rural service area. The allocation of the common costs are based on cost of service results provided in section 5.5. The table shows that the ROE for the Rural area at negative 1.5%. In effect, this overall result also means that Urban customers fully funded all ROE for the utility plus all capital reserves in 2017.

[16] Prepared based on City of Nelson 2017 Statement of Financial Information and detailed breakdown provided by Nelson Hydro.

Table 6: ROE Estimate for 2017 for Rural ($000)[17]

	Urban	Rural	Total
Net Book Value	24,542	12,577	37,119
Working Capital	916	698	1,614
Mid-Year Rate Base	**25,458**	**13,275**	**38,733**
Mid-Year Long-term Debt	4,030	2,065	6,096
Equity Portion of Rate Base	**21,428**	**11,210**	**32,638**
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Power Purchase Costs	1,675	5,150	6,825
share	*25%*	*75%*	
O&M Expenses - share of common	1,571	1,158	2,729
share	*58%*	*42%*	
Interest Expense	164	84	248
Total Expenses	**5,651**	**7,714**	**13,365**
ROE		-169	
ROE %		-1.5%	

[17] The allocation of the long-term debt is based on net book value of assets.

5.0 COST OF SERVICE

Under normal ratemaking principles, the relative levels of rates charged to the various customer classes of a utility are ideally developed based on principles of "cost of service", the most widely accepted standard applied for regulated utilities to determine whether rates are just and reasonable. This involves determining a fair allocation of total costs to the various classes based on their usage characteristics. The Cost of Service ("COS") concept retains the concept of used and useful – for example, if a customer class does not use a component of the system (e.g., distribution), its rates are not to include the costs of that component of the system; likewise if only one class benefits from specific assets (such as streetlights) all costs related to those assets are to be allocated to the relevant class. Also among the critical cost of service theory is the concept of the different "products" that the utility provides, most notably the distinct products of (i) peak demand (including reliability), (ii) energy, and (iii) customer services, and the appropriate ways to track the cost causation of each of these aspects of the system.

A cost of service study starts with a utility's revenue requirement, and in general has three key steps – functionalization of the costs (determining what function or role the costs relate to, such as generation, transmission/distribution and general), classification (for each function, determining what types of use drive the cost, such as demand, and/or energy, customer or direct assigned) and allocation (determining which users impose loads of the specified type).

The COS for Nelson Hydro includes one more step to allocate costs. Prior to functionalization, where possible, the costs are first allocated directly to the service area where the cost responsibility arises; i.e., Urban and Rural.

It is important to recognize that Cost of Service is not an exact science. All Cost of Service studies are recognized to report results with a “Range of Reasonableness” (typically either +/- 5% or +/- 10%). For this reason, a balanced effort is required in producing Cost of Service analysis, and increased efforts at precision in Cost of Service can ultimately be counterproductive if (a) considerable additional effort is required, (b) the data required to perform the extra analysis is not available or is not reliable, and (c) the impact on the results are unlikely to exceed the degree of imprecision or Range of Reasonableness inherent in the study. For a small utility such as Nelson Hydro, these effects can be particularly magnified.

5.1 ALLOCATION OF COSTS TO SERVICE AREAS

The O&M expenses as well as capital assets are allocated to the service areas based on information provided by Nelson Hydro.

The costs are allocated into three groups:

- Urban – the costs which are 100% related to serve Urban customers;
- Rural – the costs which are 100% related to serve Rural customers; and
- Common – the costs which cannot be allocated 100% to Urban or Rural, and are thus broken out to all customers based on usage.

The COS is prepared separately for each cost group indicated above and the results are combined to summarize COS outcomes.

5.1.1 ALLOCATION OF RATE BASE AND RETURN ON RATE BASE

Based on a full analysis of the Nelson Hydro system, it has been determined that there are no common capital assets – each capital asset recorded can be directly allocated to one of the service areas. Table 7 below provides allocation of capital assets into Urban and Rural.

This is accomplished based on three main considerations:

1) The hydraulic generating plant owned by the City of Nelson primarily serves the City residents (Urban customers). Where this output is insufficient for servicing all Urban needs, a portion of the purchased power from FortisBC is allocated to serve Urban needs. Rural needs are served from purchased power.

2) Transmission poles/lines are allocated as common assets considering the power transmitted using the transmission lines serve both Urban and Rural customers.

3) Nelson Hydro does not record any “general” assets that are common in the utility industry, such as trucks or buildings. These assets are instead provided from the overall City pool of assets, and an internal accounting charge is imposed from Nelson Hydro’s use of these assets. This charge is included in the O&M portion

of the revenue requirement[18], and as a result there are no assets recorded for these components. Note that the current study did not attempt to complete a test of the methods for allocating these costs internally, but accepted the results of the standard City accounting approaches.

Table 7: Allocation of Capital Assets ($000)[19]

	Mid-year Balance	Urban	Rural	Common
Generation Plant				
Generating Stations	13,371	13,371	0	0
Substations	860	860	0	0
Subtotal	**14,230**	**14,230**	**0**	**0**
Transmission and Distribution Plant				
Transmission	5,689	0	0	5,689
Substations	6,456	6,131	325	0
Primary and Secondary Poles & Conduct.	12,431	3,326	9,105	0
Underground Conduct. & Devices	5,910	3,680	2,231	0
Transformers	4,784	2,613	2,171	0
Meters	1,216	729	486	0
Streetlight	54	54	0	0
Other	204	204	0	0
Subtotal	**36,744**	**16,737**	**14,318**	**5,689**
Total	**50,974**	**30,967**	**14,318**	**5,689**
Accumulated Amortization	**13,855**	**9,072**	**3,758**	**1,025**
Net Book Value	**37,119**	**21,895**	**10,560**	**4,664**

The working capital portion of the rate base cannot be allocated 100% to Urban or Rural, therefore working capital requirements are allocated to common.

The return on rate base for each service group was calculated based on the following approach:

[18] It was indicated by the City of Nelson that the charges are recover operating and maintenance costs as well as depreciation expenses. Not return on rate base included for those assets.
[19] Prepared based on detailed breakdown provided by Nelson Hydro.

a) Identify the return on rate base based on total rate base and return as per Table 4 which would be 13.52%[20]; and

b) Apply the return on rate base to allocated group rate base.

The amortization expense is calculated for each assets and therefore allocation to Urban and Rural service areas is available similar to the capital assets.

5.1.2 ALLOCATION OF O&M EXPENSES

The accounting for Nelson Hydro permits a portion of the O&M expenses to be directly charged to Urban or Rural. For example, the labour costs related to the City of Nelson distribution system are recorded under a separate account “Distribution-City”, while the labour costs related to distribution systems in rural areas are recorded under account “Distribution-S Shore Labour” and/or “Distribution-N Shore Labour”. These types of expenses can be directly allocated to Urban or Rural. However, the expenses under accounts such as “Computer Services Labour” cannot be directly allocated and need to be under a common cost group.

Water License Reserve transfers to the City of Nelson are allocated to the Urban service area. This was reviewed by the BCUC as part of Nelson Hydro’s 2017 and 2018 Rate Applications [please see section 1.3 for details].

The purchased power costs are allocated based on sales and estimated peak demand. Table 8 below provides the approach used for allocation of the energy portion of

[20] Calculated based on estimated return on rate base at $5.237 million [$4.989 million ROE before Capital Reserve Transfer and $0.248 million interest charges] and mid-year rate base at $38.733 million.

purchased power costs. Based on sales and generation information provided by Nelson Hydro, it is estimated that about 79,524 MW.h of annual sales to Urban customers are supplied through Hydro's own generation and about 14,800 MW.h through purchased power. The Urban customers share about 17.7% of energy portion of power purchase costs, while Rural customers share the remaining 82.3%.

The allocation of the demand portion of purchased power costs are prepared based on feeder loading study conducted by Nelson Hydro that shows based on 2014-2017 actual peak numbers the Urban customers share about 32.3% of demand portion of power purchase costs, while Rural customers share the remaining 67.7%. The share of the demand purchases for Urban customers is higher compared to energy share.

Table 8 illustrates allocation percentages for purchased power costs.

Table 8: Allocation of Purchased Power Costs[21]

	2017 Actual Total	Own Generation	Purchased Power	Share of Purchased Power
	MW.h	MW.h	MW.h	%
	A	B	C=A-B	D
Total Generation and Power Purchases	182,375	92,951	89,424	
Power Sales	7,838	7,838		
Net Utility Load	174,537	85,113	89,424	
Urban Sales	94,323	79,524	14,800	17.7%
Rural Sales	68,752	-	68,752	82.3%
Losses	11,461	5,589	5,872	
Losses % of sales	7.0%	7.0%	7.0%	
Demand Purchases based on review of 2014-2017 actuals				
Urban				32.3%
Rural				67.7%

[21] The Fortis BC basic charge for Nelson Hydro is not significant compared to the total purchase cost and included in demand portion of power purchase costs.

Table 9 below provides summary of allocated O&M expenses.

Table 9: Allocation of O&M Expenses ($000)[22]

	2017 Actual	Allocation		
	Total	Urban	Rural	Common
O&M Expenses	**12,086**	**3,255**	**6,190**	**2,642**
Wages and Benefits	***2,173***	***522***	***278***	***1,373***
Generation	*151*	*151*	*0*	*0*
Transmission and Distribution	*474*	*180*	*278*	*16*
General	*1,548*	*191*	*0*	*1,358*
Supplies and Services	***9,255***	***2,075***	***5,912***	***1,268***
Generation	*332*	*2*	*0*	*331*
Power Purchases	*6,825*	*1,675*	*5,150*	*0*
Transmission and Distribution	*995*	*193*	*749*	*54*
General	*1,103*	*206*	*13*	*884*
Water Licence Reserve Transfer	***658***	***658***	***0***	***0***
Amortization	1,031	662	282	87
Interest charges	248	164	84	0
Total Expenses	**13,365**	**4,080**	**6,556**	**2,729**

5.2 FUNCTIONALIZATION OF THE COSTS

The next step in COS is functionalization of the costs, i.e. determining to which function or role the costs relate. In common utility practice the costs functionalized to Generation, Transmission, Distribution and General plant.

For the purposes of Nelson Hydro's COS, the costs are functionalized to:

- Generation – generation assets, plant operating cost, purchased power, etc.

[22] The numbers are subject to rounding.

- Transmission and Distribution – these functions are combined and include transmission and distribution assets, costs related to operating and maintenance of these assets and proving service.

- General plant – general cost, such as computer services, etc.

5.2.1 FUNCTIONALIZATION OF CAPITAL ASSETS

There are no general plant assets owned by Nelson Hydro[23]. The functionalization of other capital assets are provided in Tables 5 and 7.

5.2.2 FUNCTIONALIZATION OF O&M EXPENSES

As reviewed in sections above, the O&M expenses are directly charged to separate accounts for each cost centre (for example, account "Distribution-City"). This allows the analysis to functionalize the O&M expenses into generation, transmission/distribution and general expenses. In order to minimize the size of the COS, the cost centres or accounts have been grouped into the major cost categories (e.g. the distribution category includes costs related to distribution labour, distribution supplies and services, etc.) Table 10 below provides summary of total expenses by function.

[23] Most of the property and equipment to carry out general service are rented or shared with City of Nelson.

Table 10: O&M Expenses by Function ($000)

	Total Expenses
Generation Expense	
Plant Operations	439
Substations	45
Water Licence Reserve Transfer	658
Subtotal	**1,142**
Power Purchase	**6,825**
Transmission and Distribution Expense	
Transmission Lines	23
Distribution	1,223
Substations - Transmission and Distribution	145
Meter Reading	79
Subtotal	**1,469**
Admin. & General Expense	
General Admin	2,125
Operations	526
Subtotal	**2,651**
Total O&M Expense	**12,086**

5.3 CLASSIFICATION OF THE COSTS

Once costs are functionalized, they are classified based on cost drivers between demand, energy, customer and revenue. This step is more complicated as it cannot be developed using accounting or other information from Nelson Hydro, but instead uses detailed load data. In order to avoid the need for development of specific classification factors based on any range of detailed studies the Nelson Hydro COS uses broad industry-accepted factors which are then tested for reasonableness for application to Nelson Hydro.

The following classification categories are used for Nelson Hydro COS:

- Demand related
  - Coincident Peak (CP) – mostly comprised of generation and transmission related costs
  - Non-Coincident Peak (NCP) – mostly distribution related costs
- Energy related
- Customer related
  - Actual number of customers– poles, underground conduct and devices
  - Weighted number of customers– transformers and meters

<u>Generation Plant</u>

The determination of appropriate generation classification factors takes into account the relationship between capacity (peak demand) and energy requirements. The cost of capacity relates to the cost to accommodate peak loads at the time of the highest system load in the system. The cost profile of a pure energy use is that of a sustained consumption of kilowatt-hours throughout the year.

Some small isolated utilities or large thermally based utilities focus on planning processes for generation facilities that are primarily concerned with ensuring sufficient capacity is available to meet the peak. Demand is the primary cost driver for generation infrastructure, therefore generation plant assets are usually classified as 100% demand. However, the utilities within an interconnected system, and in particular those using hydraulic generation, use split demand/energy ratios. For example, BC Hydro classified generation 55% to demand and 45% to energy (BCUC Order G-111-07[24] and BC Hydro BC Hydro 2015 Rate Design Negotiated Settlement Agreement[25]), while Fortis BC (BCUC Order G-156-10[26]) classified generation 20% to demand and 80% to energy[27]; the Yukon Utilities Board approved classification factor of 40% to demand and 60% to energy for Yukon Energy and Yukon Electrical in their most recent combined Phase II General Rate Application ("GRA")[28]; Newfoundland and Labrador Hydro calculates the

[24] http://www.bcuc.com/Documents/Orders/2007/DOC_16717_G-111-07_BCH%202007%20Rate%20Design-FACOS%20approved.pdf [accessed on September 21, 2018].

[25] BC Hydro, 2015 Rate Design Negotiated Settlement Agreement http://www.bcuc.com/Documents/Proceedings/2016/DOC_46087_04-11-2016_COS-Negotiated-Settlement-Agreement.pdf [accessed on September 21, 2018].

[26] http://www.bcuc.com/Documents/Orders/2010/DOC_26338_G-156-10_FortisBC-2009-Rate-Design-Decision.pdf [accessed on September 21, 2018].

[27] The new application filed by Fortis BC also shows 20% demand and 80% energy noting that it is based on "the basis of the demand / energy split for equivalent BC Hydro 3808 Purchases". FortisBC Inc. (FBC) 2017 Cost of Service Analysis and Rate Design Application, page 49. http://www.bcuc.com/Documents/Proceedings/2018/DOC_50507_B-1_FBC-2017-Rate-Design-Application.pdf [accessed on September 21, 2018].

[28] http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/1158_Board%20Order%202010-13%20Appendix%20A.pdf [accessed on September 21, 2018].

classification ratios based on system load data which resulted 45.6% to demand and 54.4% to energy in its 2017 GRA.[29]

In the case on Nelson Hydro, two overriding considerations drive the choice of classification factors:

1) Use of factors that recognize the very seasonal nature of the hydraulic generation owned by Nelson Hydro, which provides far more summer energy and much more limited winter peak capacity output; and

2) Use of factors that have an established and accepted role in BC rate setting.

Based on these considerations, it is recommended use classification factors for generation as approved for Fortis BC, i.e. 20% to demand and 80% to energy.

The generation related expenses (other than purchased power) are classified based on the average classification factor for generation plant.

Transmission/Distribution Plant

Investment in transmission/distribution plant is typically driven by the number and location of customers, and by the peak demand imposed by those customers. Investment in transmission/distribution plant does not typically vary with the consumption of energy. Therefore transmission/distribution plant is normally classified

[29] Schedule 4.1, Exhibit 14 of 2017 GRA http://www.pub.nf.ca/applications/NLH2017GRA/applications/NLH%202017%20General%20Rate%20Application%20-%20Volume%20III%20-%20Revision%205%20-%202018-07-04.PDF [accessed on September 21, 2018].

to demand and customer. This is consistent with the practice followed by basically all other Canadian utilities.

The following provides a summary of classification factors used for Nelson Hydro:

- **Transmission Plant:** There are effectively two types of transmission common for the purposes of COS analysis. The first is "generation integration transmission", which is a unique category of transmission assets largely playing a role of delivering power from a distant generating station into the main load and grid transmission centers. The second is the more common "grid" type of transmission. Generation integration transmission is typically classified in the same manner as the underlying generation plant. Most of the utilities, including BC Hydro and Fortis BC classify the grid transmission plant 100% to demand.[30] The same approach was used for Nelson Hydro and transmission plant was classified 100% to demand.

- **Distribution Poles, Overhead Conductors / Underground Conduits, Line Transformers, Meters and Metering Equipment:** Investment in these assets is driven partly by the demand placed on the system and partly by the number of customers to be served. It can be difficult to develop comparisons to other utilities with respect to distribution classification factors, as not all utilities account for similar assets similarly. Also utilities classify distribution costs to demand and customer using widely different factors. For example, Newfoundland and

[30] For example, FortisBC Inc. (FBC) 2017 Cost of Service Analysis and Rate Design Application, page 49. http://www.bcuc.com/Documents/Proceedings/2018/DOC_50507_B-1_FBC-2017-Rate-Design-Application.pdf [accessed on September 21, 2018].

Labrador for its Island Interconnected System classified 58% of distribution pole and fixtures to demand, while Yukon Energy used a classification of 56% to demand, and in its 2009 COSA Fortis BC classified 96% of these costs to customer classes and the new application filed by Fortis BC shows 81% of distribution pole and fixtures are proposed to be classified to customer classes. However, these utilities classify some other distribution assets more towards demand, for example YEC classified transformers 72% to demand, Fortis BC classified substations 100% to demand.[31] In order to develop a reasonable approach that can be applied to Nelson Hydro without requiring new asset classification categories, and that is representative of the BC experience, the classification factors used by BC Hydro were determined to be appropriate. These factors lead to all distribution assets being classified as 73% demand related and 27% customer related.[32]

- **Streetlights:** These assets were directly assigned to the streetlight customer class.

The transmission and distribution related expenses are classified based on average classification factor for transmission/distribution plant.

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[31] The cost of each distribution plan costs will have impact to the total factor for the function. For example, based on Fortis BC 2009 Rate Design Application, Schedule 4.2 the total distribution plant classified to demand is 42%, and about 58% classified to customer. FortisBC's new 2017 Cost of Service Analysis and Rate Design Application shows total distribution plant classified to demand is 47%.

[32] BC Hydro, 2015 Rate Design Negotiated Settlement Agreement http://www.bcuc.com/Documents/Proceedings/2016/DOC_46087_04-11-2016_COS-Negotiated-Settlement-Agreement.pdf [accessed on September 21, 2018].

General Plant

Based on information provided by Nelson Hydro, there are no general plant related assets. Facilities and equipment for general use are shared with City of Nelson.

Other rate base cost categories were classified to customer, demand, and energy related cost as follows:

- Accumulated Amortization:
  - Generation plant related – based on the proportion of total generation assets classified to customer, demand, and energy categories.
  - Distribution plant related – based on the proportion of total distribution assets classified to customer, demand, and energy categories.
- Working Capital:
  - Based on the proportion of total assets classified to customer, demand, and energy categories. The inventory portion of the working capital requirements can be further detailed based on breakdown of inventory balances, however, this would be a time consuming process and will have very small impact to functionalization.

5.4 ALLOCATION OF THE COSTS TO CUSTOMER CLASSES

The next step of the COS process involves the allocation of costs into customer classes.

5.4.1 DEMAND ALLOCATION FACTORS

In the development of demand allocation factors for each customer group are typically the most challenging steps of the allocation process. Two steps are required.

1. Determining the most appropriate method for allocation of demand-related costs; and

2. Development of the appropriate demand data.

Generation demand-related costs are generally considered to be related to coincident demands (i.e., customer group peak at the time of a system peak), since sufficient capacity must be provided to meet the demands of all customers at the time of the system peak. Therefore generation demand-related costs are allocated based on the class's share of the total coincident peak (CP). As Nelson Hydro has a winter peaking system, and there are relatively small differences between customer usage characteristics, there is expected to be little difference between allocation based on the simpler approach of a single Coincident Peak (1CP) and the more complicated approaches based on multiple coincident peaks (e.g., 2 CP, 4 CP, reflecting more winter months). Given data limitations are also relevant to the choice of allocation factor, the use of a 1 CP was determined to be appropriate.

In contrast to the Coincident Peak allocation, distribution line transformers, poles and fixtures and other distribution system components are sized to meet the maximum demands of the local customers regardless of time of occurrence. For this reason, distribution and general plant demand-related costs were allocated on the basis of non-coincident demands utilizing the class non-coincident peak (NCP).

Coincident Peak and Non-coincident peaks are not metered at the class level. Therefore determining the allocation requires estimates of the customer class load factors and coincidence factors in order to estimate the coincident and non-coincident peaks for each class. The research was not undertaken on individual customer classes as it requires significant amount of load research effort and data that is not available. Therefore, customer class load factor and coincidence factors are estimated based on factors used by Fortis BC in its 2009 COS as per Table 11 below.

Table 11: Load Parameters used for COS[33]

Customer Class	NCP Load Factor	Coincidence Factor
Residential	40%	80%
Commercial	43%	75%
Streetlights	27%	100%

The load parameters shown in Table 11 resulted in a calculated CP (before losses) of 35.7 MW. This is slightly lower compared to the 2017 actual peak at 39.7 MW (including losses) which occurred in January 2017. The actual peak was impacted by colder than

[33] Fortis BC 2009 COSA annual NCP load factor in Schedule 8.1 and system coincident factor in Schedule 8.2 http://www.bcuc.com/Documents/Proceedings/2009/DOC_23627_B-1_FortisBC%202009%20Rate%20Design%20Application.pdf [accessed on September 21, 2018]. FortisBC's new 2017 Cost of Service Analysis and Rate Design Application, Schedule 8.1 [http://www.bcuc.com/Documents/Proceedings/2018/DOC_50507_B-1_FBC-2017-Rate-Design-Application.pdf] shows that proposed annual NCP load factors for residential class at 42% compared to 40% in the 2009 COSA, commercial at 55% compared to 43% in the 2009 COSA and street lighting at 47% compared to 27% in the 2009 COSA. However, the new proposed NCP load factors are not fully reviewed by the BCUC. Therefore, for the purposes of Nelson Hydro COSA, Fortis BC's 2009 COSA numbers have been used. The impact of new NCP load factors is provided in section 5.5.

normal weather in January 2017 as discussed in section 2 above. Also, with about 7% losses the calculated CP would be about 38.2 MW which is within a reasonable range and will not have any distorting effects on the Cost of Service unless one class is materially prejudiced in respect of the peak as compared to any other class. There is no basis to conclude, on the available data, that any class is disproportionately affected by this peak allocation.

5.4.2 ENERGY ALLOCATION FACTORS

Energy-related costs were allocated to customer classes based on the total kilowatt-hour sales to each customer class. The allocation ratios were developed based on the actual sales for 2017.

5.4.3 CUSTOMER ALLOCATION FACTORS

Customer-related costs were allocated to customer classes based on both the actual number of customers and a revised “weighted” number of customers.

Common industry practice is to allocate the expenses that do not vary with the type of customers or its consumption of electricity as customer-related costs.

However for some costs a “weighted” customer count is used, typically for costs that vary somewhat with the type of customer or its consumption of electricity. For example, metering device costs are different for commercial customers than residential customers as commercial customers typically require more expensive meters. A weighted number of customers was used for allocation of meters and line transformer assets, and related expenses. Most of the utilities reviewed use a customer weighting of 1.0 for residential and 3.0 for commercial customers.

5.5 COS OUTCOMES

Table 12 below provides 100% COS rates based on COS analysis.

Table 12: 2017 COS Outcomes[34]

	2017 COS Allocation $000	2017 Actual Revenues $000	RCC Ratio %	Compare 90%-110% Range
Residential - Urban	$4,683	$4,939	105.5%	within
Residential - Rural	$8,161	$6,258	76.7%	low
Commercial - Urban	$4,164	$5,801	139.3%	high
Commercial - Rural	$1,213	$1,255	103.4%	within
Streetlight	$133	$101	75.6%	low
Total	**$18,354**	**$18,354**	**100.0%**	

The tables show that Revenue to Cost Coverage (RRC) ratios are as follows:

- Residential Urban RCC at 105.5%, which is within reasonable RCC range (assuming 90%-110% of the cost);
- Residential Rural RCC at 76.7% which is outside of reasonable RCC range;
- Commercial Urban RCC at 139.3% which is outside of reasonable RCC range;

[34] As indicated in section 5.4.1, FortisBC's new 2017 Cost of Service Analysis and Rate Design Application, Schedule 8.1 [http://www.bcuc.com/Documents/Proceedings/2018/DOC_50507_B-1_FBC-2017-Rate-Design-Application.pdf] shows that proposed annual NCP load factors for residential class at 42% compared to 40% in the 2009 COSA, commercial at 55% compared to 43% in the 2009 COSA and street lighting at 47% compared to 27% in the 2009 COSA. Using the new proposed NCP load factors shows that Residential Urban RCC would be 100.8% compared to 105.5%, Residential Rural RCC would be 75.3% compared to 76.7%, Commercial Urban RCC would be 147.8% compared to 139.3% and Commercial Rural RCC would be 112.3% compared to 103.4%. The overall conclusions would be the same: residential Rural paying much less than it cost and it is being subsidized mostly by Commercial Urban customer class.

- Commercial Rural RCC at 103.4% which is within a reasonable RCC range; and
- Streetlight RCC at 75.6% which is below reasonable RCC range, however, the impact to the other classes are not significant considering very small size of the class [approximately 1% of total revenue requirement].

5.6 COMPARISON OF RATES AND RATE DESIGN TO FULLY ALLOCATED COSTS

Table 13 below provides the average unit costs based on COS analysis.

Most utilities do not have material (if any) demand charges for residential and streetlight customers and customer charges for commercial customers are not typical. However, Nelson Hydro rates include a customer charge for commercial and a demand charge for residential customers with over 20 kW of load. Table 14 also shows COS rates after the removal of demand charges for residential customers, demand and customer charges for streetlight customers. No demand charges are assumed for residential customers.

Table 13: 2017 COS Outcomes – Average Unit Costs

	Residential		Commercial		Streetlight	
	Urban	Rural	Urban	Rural	Urban	Rural
Average Unit Costs as per COS						
DEMAND - $/kW (assumed CP)	$19.14	$26.77	$19.86	$27.68	$16.97	$24.05
ENERGY - cents/kW.h	3.34	5.06	3.34	5.06	5.16	$5.39
CUSTOMER - $/Cust/bi-monthly	$27.53	$35.40	$36.54	$46.90	$27.53	$35.40
Average Unit Costs after removal demand charges for residential, demand and customer charges for streetlight.						
DEMAND - $/kW (assumed CP)	$0.00	$0.00	$19.86	$27.68	$0.00	$0.00
ENERGY - cents/kW.h	8.58	12.39	3.34	5.06	13.80	17.66
CUSTOMER - $/Cust/bi-monthly	$27.53	$35.40	$36.54	$46.90	$0.00	$0.00

Table 14 below compares the 2017 COS average unit costs to the rates effective April 1, 2017[35] for residential customers.

Table 14: Comparison of Rates – Residential[36]

	Residential - Urban		Residential - Rural	
	2017 COS	Rates Effective April 1, 2017	2017 COS	Rates Effective April 1, 2017
ENERGY - cents/kW.h	8.58	10.13	12.39	10.13
CUSTOMER - $/Cust/bi-monthly	$27.53	$15.63	$35.40	$15.63

Table 15 below compares the 2017 COS average unit costs to the rates effective April 1, 2017 for commercial customers.

Table 15: Comparison of Rates – Commercial

	Commercial - Urban		Commercial - Rural	
	2017 COS	Rates Effective April 1, 2017	2017 COS	Rates Effective April 1, 2017
DEMAND - $/kW	$19.86	$7.59	$27.68	$7.81
ENERGY - cents/kW.h	3.34	11.54	5.06	11.89
CUSTOMER - $/Cust/bi-monthly	$36.54	$35.82	$46.90	$36.92

In order to simplify the presentation into a pure average cents/kW.h calculation, Table 16 provides breakdown of COS costs for four major customer groups in comparison with 2017 average actual rates estimated based on revenues from customers divided by sales in kW.h (which are a mix of the rates applied from January 1, 2017 to March 31, 2017, and the higher rates approved April 1, 2017).

[35] For the rate comparison purposes April 2017 rates have been used as the COS is run for 2017 actuals. An increase of 2.25% was approved effective April 1, 2018 [BCUC G-124-18].
[36] Under the existing rates there is a demand charge of $7.26/kW for residential customers with more than 20 kW demand. For the purposes of this comparison existing demand charge rates are not included in the table.

As table shows, based on COS analysis the costs to serve Rural customers average about 3.8 cents/kW.h more than for Urban customers (mostly due to transmission/distribution related costs as well as cost for power purchases) and the costs to serve Residential customers average about 1.6 cents/kW.h higher than to serve Commercial customers (mostly due to the larger average size and expected different load characteristics of the Commercial loads). However, the actual revenues per kW.h for 2017 shows that the commercial customers paid slightly higher compared to the residential customers.

Table 16: Comparison of Average COS Rates

	Average Cost per kW.h sales		Average Cost per kW.h sales	
	Residential - Urban	Residential - Rural	Commercial - Urban	Commercial - Rural
2017 COS Average Cost per kW.h sales - cents/kW.h				
Hydro Generation				
Demand related	0.5	0.0	0.5	0.0
Energy related	2.1	0.0	2.1	0.0
Power Purchases				
Demand related	1.1	3.0	0.9	2.6
Energy related	0.7	4.5	0.7	4.5
Transmission/Distribution				
Demand related	2.5	3.6	2.3	3.4
Customer related	1.2	1.2	0.3	0.7
General				
Demand related	1.1	0.9	1.0	0.8
Energy related	0.5	0.4	0.5	0.4
Customer related	0.5	0.4	0.1	0.1
Total COS	**10.3**	**13.9**	**8.5**	**12.5**
Average cents/kW.h based on 2017 Actual Revenues	**11.0**	**10.6**	**11.8**	**13.0**
Actual over COS, cents/kW.h	0.8	-3.3	3.3	0.5
Actual over COS, %	7%	-24%	39%	4%