QULLIQ ENERGY CORPORATION

2018/19 General Rate Application

October 2017

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1.0 INTRODUCTION AND APPLICATION

1.1 APPLICATION

Qulliq Energy Corporation ("Corporation" or "QEC") hereby submits its combined Phase I and Phase II General Rate Application ("GRA" or "Application") for the 2018/19 test year and applies, pursuant to Section 12 of the Utility Rates Review Council Act ("the Act"), for an instruction or instructions by the Minister:

- Approving the Corporation's forecast 2018/19 test year revenue requirement of $134.047 million as set out in Schedule 4.1;
- Approving the Corporation's proposed rates effective April 1, 2018 and April 1, 2019 as set out in Schedules 8.1 through 8.6;
- Approving the revisions to the Terms and Conditions of Service set out in Chapter 9; and
- For any such further and other instructions within the Minister's authority as the Corporation may request and the Minister determines proper.

1.2 BACKGROUND

A May 26, 2011 letter from the Minister to the Utility Rates Review Council ("URRC") on the URRC's 2011-01 report noted that QEC will file general rate applications in three year intervals and where feasible, QEC intends to provide future rate applications in advance of the relevant test year.

The Corporation's most recent Phase I and II GRA for the 2014/15 test year was initially filed with the Minister on November 1, 2013. That application was withdrawn on November 7, 2013 and resubmitted on December 20, 2013. The Minister referred the application to the Utility Rates Review Council for review and recommendations pursuant to Section 12 of the Utility Rates Review Council Act. In a letter dated February 14, 2014, QEC filed amendments to its application to reflect a Ministerial Instruction to retract the move toward territory-wide rates.

The URRC completed its review of the GRA and issued a final report (report 2014-05) on May 16, 2014. Following the review of the report, the responsible Minister provided an instruction dated May 30, 2014 ("May 30, 2014 Instruction") with the following instructions to QEC:

a. To impose a rate increase to all customer classes of 7.1%, for all electricity rate classes and communities at the rates outlined in the attachment identified as approved Rate Schedules to go into effect May 1, 2014.

b. To accept the attached Revised Terms and Conditions of Services approved to go into effect May 30, 2014.

c. To accept the revised Fuel Stabilization Rate Fund Instruction approved to go into effect May 30, 2014.

1.3 OUTLINE OF THE APPLICATION

The Application is organized as follows:

- Chapter 2 provides an overview of the Corporation;
- Chapter 3 reviews system sales and generation requirements;
- Chapter 4 reviews the revenue requirement for the Test Year;
- Chapter 5 reviews the shortfall at existing rates;
- Chapter 6 reviews the Corporation’s rate base;
- Chapter 7 reviews the COS study and results;
- Chapter 8 reviews the Corporation’s proposed rate design, as well as the proposed rate adjustments effective April 1, 2018 and April 1, 2019;
- Chapter 9 reviews the Corporation’s proposed changes to the Terms and Conditions of Service; and
- Chapter 10 provides responses to previous URRC recommendations.

2.0 CORPORATE OVERVIEW

2.1 INTRODUCTION

This chapter sets out an overview of the Corporation, its operating environment, and the challenges and opportunities facing the Corporation today and in the future:

- Overview of the Corporation;
- Challenges and Opportunities facing the Corporation; and
- Measures Taken to Mitigate Impacts on Customers.

2.2 OVERVIEW OF THE CORPORATION

On April 1, 2001, Nunavut Power Corporation took up the mandate to supply electricity to communities in the Nunavut Territory. Renamed Qulliq Energy Corporation in 2003, the Corporation is 100% owned by the Government of Nunavut (GN).

Qulliq Energy Corporation is incorporated and operates under the Qulliq Energy Act. Rates for its electricity service are approved by the responsible Minister who receives advice from the Utility Rates Review Council pursuant to the Utility Rates Review Council Act.

QEC is the only generator, transmitter and distributor of electrical energy for retail supply in Nunavut and has approximately 15,000 electrical customers across the Territory. The Corporation generates and distributes electricity to Nunavummiut through the operation of stand-alone diesel plants in 25 communities meeting community peak demands ranging from approximately 200 kW at Grise Fiord to 10 MW at Iqaluit. The Corporation provides mechanical, electrical and line maintenance from three regional centers and administers the Corporation's business activities from a headquarters in Baker Lake and executive offices in Iqaluit.

2.3 CHALLENGES AND OPPORTUNITIES FACING THE CORPORATION

The Corporation serves a population of approximately 37,000 people[1] located in an area of 2.1 million square kilometres. Electricity systems are isolated and unconnected and therefore each must be planned and operated independently. This unique environment has a profound impact on the Corporation's operations throughout its service area. QEC is the only energy corporation in Canada without significant local energy resources or regional electricity transmission capability which leads to a substantial dependency on fossil fuels.

In order to continuously supply safe and reliable power, QEC undertakes long-term capital planning to determine which plants require upgrades and expansions or need to be completely rebuilt as they have reached the end of their useable lifespan. QEC also researches emerging alternative energy technologies to determine if they can be incorporated into the capital planning cycle.

The Corporation remains committed to reducing Nunavut's dependency on fossil fuels. QEC continues to explore renewable energy sources and implement conservation

[1] Source: Nunavut Bureau of Statistics, Nunavut Population as of October 1, 2016 http://www.stats.gov.nu.ca/en/home.aspx.

initiatives that are both financially and environmentally viable for the territory. Examples of this work include:

- QEC successfully commissioned a 2 kW solar panel demonstration project at the Iqaluit power plant. Eleven solar panels have been integrated to the grid and have been feeding power to the city since March 2016. QEC has been working with Natural Resources Canada (NRCan) on this demonstration project which will help QEC on future solar panel projects.

- QEC is implementing a Net Metering project to enable customers to install renewable energy sources that can supply surplus energy to QEC. This will allow QEC customers to offset their electricity needs with installed alternative energy sources and reduce diesel generated electricity in Nunavut.

2.4 MEASURES TAKEN TO MITIGATE IMPACTS ON CUSTOMERS

QEC together with the Government of Nunavut, have taken efforts to mitigate rate impacts on customers. These include efforts to contain the revenue requirement where possible, without sacrificing safety and reliability, as well as developing measures that provide customers with the benefits of a managed transition to the required higher rate levers.

Most notable measures include:

- **Improved Fuel Efficiency:** QEC's corporate-wide fuel efficiency has improved since the last GRA (2018/19 forecast at average of 3.76 kWh/litre compared to average of 3.71 kWh/litre in the 2014/15 GRA).

- **Station Service Improvements:** Station service has been reduced through a variety of initiatives and plant upgrades. The 2018/19 test year station service forecast is lower (3.3% of generation) than the 2014/15 forecast (3.5% of generation).
- **Moving towards territory-wide rates:** In the Ministerial Instruction dated January 29, 2014, QEC was instructed to file a Phase II rate application that provides several cost-of-service study (COS study) options for consideration in its next GRA. In this Application, the Corporation proposes moving toward territory-wide rates. This approach is better aligned with the Government of Nunavut's policy objectives and Inuit societal values. This also provides a higher degree of rate stability throughout the Territory and shares the benefits of future alternative energy investments with customers across the Territory. Further details on the Corporation's rate proposals are provided in Chapter 8.
- **Mitigate rate impacts of transition to territory-wide rates:** In order to mitigate rate impacts to customers, QEC is proposing to cap rate rebalancing increases at a maximum of 5% per year. This transition measure has been supported both by the URRC and the Government of Nunavut during the 2010/11 GRA proceeding.

  Further, in developing its rate proposal, QEC considered potential realignment of the Nunavut Electricity Subsidy (NES) program to assist with the transition to territory-wide rates.

3.0 SYSTEM SALES AND GENERATION REQUIREMENTS

3.1 INTRODUCTION

QEC's 2018/19 GRA reflects a revenue requirement based on the costs to operate the QEC system and to service the loads expected to arise in the test year.

This section sets out specific details on the QEC system, loads, generation requirements and fuel requirements including:

- System overview and comparison of 2014/15 and 2018/19 forecasts; and
- Forecast methods for 2018/19.

Schedule 3.1 sets out corporate-wide sales, revenue, line losses, generation and fuel requirements for the actual years 2014/15, 2015/16, and 2016/17, as well as forecasts for 2017/18 and 2018/19. Community-by-community detail is provided in Appendix A.

3.2 SYSTEM OVERVIEW AND DEVELOPMENTS SINCE 2014/15 GRA

3.2.1 FACILITIES

QEC is the sole generator and distributor of power for retail supply in Nunavut. QEC provides generation and distribution services to retail customers in 25 communities. Currently, QEC has no industrial or wholesale customers. All 25 communities are supplied by diesel generation.

3.2.2 MAJOR FACILITY CHANGES SINCE 2014/15 GRA

There have been several changes to QEC's facilities since the time of the 2014/15 GRA that have a material impact on power costs in Nunavut. These changes are summarized below.

Grise Fiord Power Plant: QEC was granted a major project permit for a new power plant in Grise Fiord through a Ministerial Order on March 13, 2014 as recommended in the URRC's report 2014-02 dated February 20, 2014.

Distribution Upgrades: QEC upgraded actual distribution systems and substation facilities in the communities of Sanikiluaq and Whale Cove.

- The Sanikiluaq distribution project was completed in 2015/16. The project involved replacing corroded pole mount transformers, re-conductoring primary and secondary distribution circuits and replacing vintage pole structures. Line losses for Sanikiluaq for the 2014/15 GRA were 239 MWh, after completion of the distribution upgrade line losses decreased to 199 MWh in 2016/17. 2018/19 forecast line losses are 193 MWh, this represents a reduction of 19%, or 45 MWh, over the 2014/15 GRA.

- The Whale Cove distribution upgrade involved pole replacement and relocation. The project was completed in 2015/16. Line losses for Whale Cove for the 2014/15 GRA were 97 MWh. The actual line losses decreased to 86 MWh in 2016/17. 2018/19 forecast line losses are 53 MWh, this represents a reduction of 45.0%, or 44 MWh, over the 2014/15 GRA.

Taloyoak Plant Replacement: The Taloyoak plant replacement project was completed in the 2016/17 fiscal year. QEC received a major project permit for the project by Ministerial Order dated June 9, 2011 as recommended in the URRC's report 2011-04 dated June 6, 2011.

Qikiqtarjuaq Plant Replacement: The Qikiqtarjuaq plant replacement project was completed in the 2016/17 fiscal year. QEC received a major project permit for the project by Ministerial Order dated June 9, 2011 as recommended in the URRC's report 2011-05 dated June 6, 2011.

Pangnirtung Plant Replacement: The Pangnirtung plant replacement project is expected to be in service in the 2017/18 fiscal year. The project is for the replacement of the existing power plant that was damaged by fire in April 2015.

Cambridge Bay Capacity Increase and Upgrade: In 2016/17 Cambridge Bay plant was upgraded to increase its capacity. Cambridge Bay has experienced large load growth mostly due to the addition of the Canadian High Arctic Research Station (CHARS) campus, requiring an additional capacity as well as upgrades to the existing plant.

Iqaluit Smart Grid Project: QEC implemented a Smart Grid technology installation in Iqaluit in 2015/16. The Smart Grid technology helps to optimize the benefits of converting the existing distribution system to 25kV and the upgrade of the Iqaluit main power plant. The project can also facilitate the incorporation of renewable energy into the electricity system in the future.

3.2.3 SYSTEM TRENDS SINCE 2014/15 GRA

Since the 2014/15 GRA, the system has experienced a number of changes in loads and generation. This section compares 2014/15 GRA forecasts with 2018/19 test year forecasts.

Total Sales

Table 3.1 compares total forecast sales for the 2014/15 and 2018/19 test years.

Table 3.1:
System Sales – 2014/15 GRA Forecast Compared to 2018/19

	2014/15 GRA Forecast	2018/19 Forecast	Average Annual Growth	Change in MWh
Sales by Rate Class (MWh)				
Domestic	65,547	67,763	0.8%	2,216
Commercial	105,185	109,139	0.9%	3,954
Streetlights	1,937	1,949	0.1%	11
Total Sales	**172,669**	**178,851**	**0.9%**	**6,181**

Total forecast sales for 2018/19 are higher than the 2014/15 GRA forecast by 6,181 MWh, corresponding to an average annual increase of 0.9%. The sales growth forecast average reflects some communities with large increases in sales and some communities with decreases in sales:

Communities with large increases in sales include Cambridge Bay, Gjoa Haven, Taloyoak, Rankin Inlet, Arviat, Igloolik, Naujaat, and Sanikiluaq:

- Cambridge Bay forecast sales increased from 9,631 MWh in the 2014/15 GRA to 12,388 MWh in 2018/19 (an increase of 28.6%). Cambridge Bay accounts for 6.9% of total corporate forecast sales.

- Gjoa Haven forecast sales increased from 5,053 MWh in the 2014/15 GRA to 5,525 MWh in 2018/19 (an increase of 9.3%). Gjoa Haven accounts for 3.1% of total corporate forecast sales.

- Taloyoak forecast sales increased from 3,407 MWh in the 2014/15 GRA to 3,717 MWh in 2018/19 (an increase of 9.1%). Taloyoak accounts for 2.1% of total corporate forecast sales.

- Rankin Inlet forecast sales increased from 16,151 MWh in the 2014/15 GRA to 17,006 MWh in 2018/19 (an increase of 5.3%). Rankin Inlet accounts for 9.5% of total corporate forecast sales.

- Arviat forecast sales increased from 8,079 MWh in the 2014/15 GRA to 8,830 MWh in 2018/19 (an increase of 9.3%). Arviat accounts for 4.9% of total corporate forecast sales.

- Igloolik forecast sales increased from 6,026 MWh in the 2014/15 GRA to 6,559 MWh in 2018/19 (an increase of 8.8%). Igloolik accounts for 3.7% of total corporate forecast sales.

- Naujaat forecast sales increased from 3,409 MWh in the 2014/15 GRA to 4,157 MWh in 2018/19 (an increase of 21.9%). Naujaat accounts for 2.3% of total corporate forecast sales.

- Sanikiluaq forecast sales increased from 3,303 MWh in the 2014/15 GRA to 3,604 MWh in 2018/19 (an increase of 9.1%). Sanikiluaq accounts for 2.0% of total corporate forecast sales.

Communities with decreases in sales include Baker Lake, Pangnirtung, Cape Dorset, Resolute Bay, Kimmirut and Grise Fiord.

- Baker Lake forecast sales decreased from 8,799 MWh in the 2014/15 GRA to 8,268 MWh in 2018/19 (about 6.0% decrease reflecting lower actual sales in 2015/16 and 2016/17). Baker Lake accounts for 4.6% of total corporate forecast sales.

- Pangnirtung forecast sales decreased from 6,237 MWh in the 2014/15 GRA to 6,029 MWh in 2018/19 (about 3.3% decrease reflecting lower actual sales in 2014/15 through 2016/17). Pangnirtung accounts for 3.4% of total corporate forecast sales.

- Cape Dorset forecast sales decreased from 6,042 MWh in the 2014/15 GRA to 5,292 MWh in 2018/19 (about 12.4% decrease reflecting lower actual sales in 2015/16 and 2016/17). Cape Dorset accounts for 3.0% of total corporate forecast sales.

- Resolute Bay forecast sales decreased from 4,032 MWh in the 2014/15 GRA to 3,791 MWh in 2018/19 (about 6.0% decrease reflecting lower actual sales in 2015/16 and 2016/17). Resolute Bay accounts for 2.1% of total corporate forecast sales.

- Kimmirut forecast sales decreased from 1,955 MWh in the 2014/15 GRA to 1,820 MWh in 2018/19 (about 6.9% decrease reflecting lower actual sales in 2015/16 and 2016/17). Kimmirut accounts for 1.0% of total corporate forecast sales.

- Grise Fiord forecast sales decreased from 1,072 MWh in the 2014/15 GRA to 1,015 MWh in 2018/19 (a decrease of 5.3%). Grise Fiord accounts for about 0.6% of total corporate forecast sales.

Domestic Sales

Forecast increases in domestic sales for 2018/19 relative to 2014/15 are approximately 2,216 MWh or a 0.8% average annual increase. Approximately 25.3% (or 560 MWh) of this increase relates to increased loads in Iqaluit.

Other communities forecast to experience material domestic sales growth are Cambridge Bay (124 MWh increase over 2014/15 forecasts, or 5.6% of the total Corporate-wide domestic sale increase), Gjoa Haven (185 MWh increase over 2014/15 forecasts, or 8.3% of the total Corporate-wide domestic sale increase), Taloyoak (also about 185 MWh increase over 2014/15 forecasts, or 8.3% of the total Corporate-wide domestic sale increase), Arviat (319 MWh increase over 2014/15 forecasts, or 14.4% of the total

Corporate-wide domestic sale increase), and Pond Inlet (227 MWh increase over 2014/15 forecasts, or 10.2% of the total Corporate-wide domestic sale increase).

The high growth in these communities is consistent with recent population growth trends, housing development and economic activity. The Statistics Canada Census population growth data between 2011 and 2016 for these communities indicates about 9.8% growth in Cambridge Bay, 3.5% growth in Gjoa Haven, 14.5% growth in Taloyoak, 14.6% growth in Arviat, 4.4% growth in Pond Inlet.[2]

Commercial Sales

Commercial sales are forecast to increase by 3,954 MWh or a 0.9% average annual increase for 2018/19 relative to 2014/15. Approximately 66.5% of this increase relates to increased loads in Cambridge Bay (2,630 MWh and an increase of 44.1% from 2014/15 GRA forecast to 2018/19 forecast) and Rankin Inlet (718 MWh and an increase of 6.8%). Other communities with notable increases in commercial sales are Gjoa Haven (286 MWh and an increase of 10.1%), Arviat (431 MWh and an increase of 9.7%), Naujaat (572 MWh and an increase of 30.3% reflecting increase in commercial sales in 2015/16 and 2016/17) and Igloolik (426 MWh and an increase of 13.0%). These sales increases are partly offset by reduced sales forecast in Iqaluit (605 MWh or decrease of 1.6% from 2014/15 GRA forecast to 2018/19 forecast) Baker Lake (377 MWh or decrease of 8.0%), Cape Dorset (633 MWh or decrease of 17.6%) lower sales.

[2] Statistics Canada, Census Profile, 2016 Census, http://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/index.cfm?Lang=E.

Electricity Revenues at Existing Rates

Forecast electricity revenues at existing rates for 2014/15 compared to 2018/19 are shown in Table 3.2. Electricity revenue forecasts at existing rates are higher for 2018/19 compared to 2014/15, generally matching the trends in sales (MWh).

Table 3.2:
Forecast Electricity Revenues at Existing Rates
2014/15 GRA Compared to 2018/19

	2014/15 GRA Forecast	2018/19 Forecast	Average Annual Growth
Revenue by Rate Class (000$) [1]			
Domestic	52,278	54,192	0.9%
Commercial	73,210	76,422	1.1%
Streetlights	1,739	1,749	0.1%
Total Revenue	**127,227**	**132,363**	**1.0%**

Notes:
1. Excludes rider revenues.

Generation, Losses and Station Service

Forecasts for corporate wide generation, line losses and station service are shown in Table 3.3. Forecast total generation has increased from 2014/15 to 2018/19 mirroring sales forecast increases. Line losses are forecast to increase slightly in absolute terms (231 MWh), but are expected to stay the same as a percentage of generation (4.2% in both 2014/15 and 2018/19). Station service consumption is expected to decrease slightly, both in absolute terms (decrease of 234 MWh) and as a percentage of generation (3.5% in 2014/15 to 3.3% in 2018/19).

Table 3.3:
Generation, Losses and Station Service
2014/15 GRA Forecast Compared to 2018/19

	2014/15 GRA Forecast	2018/19 Forecast	Average Annual Growth
Generation (MWh)	**187,160**	**193,338**	**0.8%**
Losses (MWh)	**7,917**	**8,148**	**0.7%**
Losses as % of Generation	*4.2%*	*4.2%*	
Station service (MWh)	**6,574**	**6,340**	**-0.9%**
Station Service as % of Generation	*3.5%*	*3.3%*	

3.2.4 NON-ELECTRICITY REVENUE

Forecast non-electricity revenues for the 2014/15 GRA compared to the 2018/19 forecast are shown in Table 3.4.

Table 3.4:
Non-Electrical Revenue
2014/15 GRA Forecast Compared to 2018/19

	Non-Electrical Revenue ($000)						
Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	Average Annual Growth 2018/19 over 2014/15 GRA
Joint Use	677	675	675	672	677	677	0.0%
Miscellaneous Charges	1,326	1,045	1,209	1,416	1,110	1,132	-3.9%
Time and Materials	1,648	591	625	724	647	739	-18.2%
Total	**3,650**	**2,311**	**2,510**	**2,812**	**2,434**	**2,548**	**-8.6%**

Non-electrical revenues are forecast to decrease from $3.650 million in the 2014/15 GRA to $2.548 million in the 2018/19 test year. This decrease is mainly driven by lower Time and Materials revenue forecast, which is prepared based on the actual Time and Materials revenue in recent years. Actual 2014/15 time and material revenues were substantially lower than the GRA forecast.

Revenues related to the government contribution towards apprentice salaries and to the housing recoveries from employees were credited as an offset to the related expense categories (salaries & wages; supplies & services) based on the URRC's recommendations in its Report 2012-01[3] to the Minister.

3.3 LOAD FORECAST METHODS

This section provides an overview of the methods used to develop the 2018/19 GRA load forecasts. QEC undertook a review of its load forecast methodology following the 2014/15 GRA as recommended by the URRC. Further details on the load forecast methodology review are provided in Chapter 10. The 2018/19 load forecast has been prepared based on a revised method resulting from that review.

QEC's load forecast is based on a two-step process:

1. A baseload forecast is prepared based on a customer forecast and a use-per-customer (UPC) forecast.
2. The baseload forecast is reviewed and adjusted if necessary for any known or reasonably expected load changes such as the addition of a major new commercial customer in a community.

QEC's load forecast includes the following components:

1. Customer forecasts by community and rate class;

[3] See Section 10.4.4 of the Application.

2. Sales (kWh) forecasts by community and rate class;
3. Generation (kWh) forecasts by community and rate class;
4. Fuel requirements; and
5. Non-electricity revenue forecast.

3.3.1 CUSTOMER FORECAST

Customer forecasts were prepared separately for the domestic and commercial rate classes.

Domestic Customers

A baseload customer forecast is prepared for domestic customer classes using the following method:

1. Calculate the average number of customers per month using the most recently available 12 months of actual customer accounts.
2. Review annual customer changes and confirm/revise any significant change in customer counts by community (e.g., 10% and higher).
3. Obtain population growth estimates from the Nunavut Bureau of Statistics and calculate the average annual growth rates for each community using the last five year population growth rate.

4. Apply the average annual population growth rates from step 2, to the most recent year of actual customer counts from step 1.[4]

Commercial Customers

A baseload customer forecast is prepared for commercial customer classes using the following method:

1. Calculate the average number of customers per month using the most recently available 12 months of actual customer accounts from the QEC billing data by community.

2. Review annual customer change and confirm/revise any significant change in customer counts by community (e.g., 10% and higher).

3. Obtain population growth estimates from the Nunavut Bureau of Statistics and calculate the average annual growth rates. This calculation is identical to step 2 in the domestic customers forecast.

4. Apply one half of the average annual population growth rates from step 2 to the most recent year of actual customer counts from step 1.[5]

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[4] The review of forecast number of customer showed that this approach resulted in high customer forecast of Igloolik [5-year average increase of about 1% compared to average population growth of 3% for the same period]. The customer count forecast for this community was adjusted to use 5-year average increase of about 1%.

[5] This is different from the 100% growth estimate applied to domestic customers. This approach is based on the assumption that domestic growth matches the population growth while commercial growth is around half of the population growth for any given community. This approach also recognizes that material new customer additions for commercial customers are likely to be identified by the top-down adjustment following completion of the base load forecast.

Once the baseload customer forecast is completed, QEC reviews the Government of Nunavut's capital plan, and monitors news releases, planning and licensing documents for resource developments to determine if adjustments should be made to the customer forecast to capture additional loads from potential new developments. The load forecast is adjusted by community based on this information. Typically these adjustments are only made when it is relatively certain the new development will proceed and it is of a material size. No changes have been made for the 2018/19 test year.

3.3.2 SALES FORECAST

Domestic and Commercial Customers

The load forecast is prepared by community. The baseload sales forecast for domestic and commercial customers is prepared using the average UPC method. The method involves the following steps:

1. A 3-year historic average annual UPC is calculated for each rate class by dividing actual total sales by actual average annual customer counts. The 3-year annual average UPC is intended to smooth out variations that may be caused by short-term weather patterns.

   The Corporation notes that there has recently been a declining UPC in large communities. For example, in Iqaluit the 2013/14 domestic UPC was about 3.7% lower compared to 2012/13, 2014/15 further decreased by 4.8%. A similar trend was observed in commercial UPC (about 4.0% and 2.9% decrease in 2013/14 and 2014/15, respectively).

In order to reflect the most recent changes in the communities a 3-year average UPC was used for both commercial and domestic forecast sales. The Cambridge Bay commercial forecast is based on average UPC of the most recent two years to reflect increased sales due to CHARS.

2. The 3-year historic average annual UPC is multiplied by the customer count forecasts.

Once the baseload sales forecast is completed, QEC reviews the Government of Nunavut's capital plan and monitors news releases, planning and licensing documents for resource developments to determine if adjustments should be made to the sales forecast to capture additional loads from potential new developments. No such adjustments were made for the 2018/19 test year forecast.

Streetlights

The streetlight sales forecast is prepared using the actual sales for the most recent year as a baseload. The baseload forecast is then reviewed for any adjustments reflecting changes in the lamp counts due to community expansions, or lamp types. No adjustments have been made to the streetlight sales.

3.3.3 GENERATION FORECAST

Line losses and station service are forecast based on a rolling 5-year average actual percentage of sales. For this calculation the model calculates the 5-year average of line losses and station service in terms of percentage of actual sales. The calculated 5-year average percentage is applied to forecast sales to calculate forecasts for line losses and station service.

Forecast generation is calculated as the sum of sales, line losses and station service.

3.3.4 FUEL REQUIREMENTS

Schedule 3.2 shows the calculation of the forecast fuel efficiencies. The forecast efficiency for each community is calculated by taking the efficiency for the 3 most recent actual years (2014/15, 2015/16 and 2016/17) and calculating a weighted average. The year with the highest efficiency is given a weighting of 3, the second highest year a weighting of 2, and the lowest efficiency year a weighting of 1. The volume of fuel required in each community is calculated by taking the forecast diesel generation and dividing it by the forecast fuel efficiency. This is consistent with the approach used in the 2014/15 GRA.

3.3.5 NON-ELECTRICITY REVENUE FORECAST

Forecasts of non-electricity revenues are prepared for three categories – joint use, miscellaneous charges, and project time and materials. Forecast joint use revenue was prepared based on the approved 2018/19 joint use rates and the existing number of connections.

Forecasts of miscellaneous charges were prepared assuming a 2% inflationary increase over the 2017/18 budget.

Project time and materials revenues include forecasts of work done by QEC for other companies, equipment rental and recovery of time and materials on small scale repair works (for example, broken pole replacements or lighting installations). Time and materials revenue forecast was prepared based on the actual Time and Materials revenue in recent years.

Schedule 3.1:
Qulliq Energy Corporation 2018/19 General Rate Application Summary of Generation, Sales and Revenue

QEC Summary

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	65,547	65,219	64,938	65,306	66,901	67,763
2	Customers	11,342	11,300	11,273	11,462	11,635	11,812
3	Av. MWh Sales/Cust.	5.78	5.77	5.76	5.70	5.75	5.74
4	Revenue (000s)	52,278	50,319	50,920	51,520	53,527	54,192
5	Cents/kWh	79.76	77.15	78.41	78.89	80.01	79.97
	Commercial						
6	Sales (MWh)	105,185	103,060	106,378	107,283	108,146	109,139
7	Customers	3,330	3,188	3,215	3,259	3,283	3,307
8	Av. MWh Sales/Cust.	31.59	32.33	33.09	32.92	32.94	33.00
9	Revenue (000s)	73,210	71,423	74,326	74,231	75,828	76,422
10	Cents /kWh	69.60	69.30	69.87	69.19	70.12	70.02
	Streetlights						
11	Sales (MWh)	1,937	1,937	1,937	1,940	1,949	1,949
12	Revenue (000s)	1,739	1,723	1,727	1,759	1,749	1,749
13	Cents /kWh	89.78	88.93	89.14	90.68	89.78	89.78
	Total						
14	**Sales (MWh)**	**172,669**	**170,216**	**173,253**	**174,529**	**176,995**	**178,851**
15	Customers	14,672	14,488	14,488	14,721	14,918	15,119
16	Revenue (000s)	127,227	123,465	126,973	127,510	131,104	132,363
17	Cents /kWh	73.68	72.53	73.29	73.06	74.07	74.01
	GENERATION (MWh)						
18	**Total Station Service**	**6,574**	**6,267**	**5,962**	**6,115**	**6,502**	**6,340**
19	**Station Service - % of Gen.**	3.5%	3.4%	3.2%	3.2%	3.4%	3.3%
20	**Total Losses**	**7,917**	**7,601**	**7,791**	**8,323**	**8,238**	**8,148**
21	**Losses - % of Gen.**	4.2%	4.1%	4.2%	4.4%	4.3%	4.2%
22	**Total Generation**	**187,160**	**184,084**	**187,005**	**188,966**	**191,736**	**193,338**
	Source						
23	Diesel Generation (MWh)	187,160	184,084	187,005	188,966	191,736	193,338
24	Diesel Efficiency (KWh/L)	3.71	3.71	3.74	3.76	3.76	3.76
25	Liters (000s)	50,421	49,622	49,979	50,196	50,948	51,355
	Peak						
26	Peak Load (KW)	35,213	35,005	34,971	34,847	35,804	36,017
27	Load Factor	61%	60%	61%	62%	61%	61%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule 3.2:
Qulliq Energy Corporation 2018/19 General Rate Application Fuel Efficiency Forecast

Line No.	PLANT #	PLANT NAME	2014/15 Generation (KWh)	2014/15 Fuel consump. (Litre)	2014/15 Fuel Efficiency (kWh/L)	2015/16 Generation (KWh)	2015/16 Fuel consump. (Litre)	2015/16 Fuel Efficiency (kWh/L)	2016/17 Preliminary Actual Generation (KWh)	2016/17 Preliminary Actual Fuel consump. (Litre)	2016/17 Preliminary Actual Fuel Efficiency (kWh/L)	Weighted Fuel Efficiency 3	Weighted Fuel Efficiency 2	Weighted Fuel Efficiency 1	Weighted Average Fuel Efficiency (kWh/L)
			A	B	C=A/B	D	E	F=D/E	G	H	I=G/H	J=MAX(C,F,I)x3	K=MED(C,F,I)x2	L=MIN(C,F,I)x1	M=(J+K+L)/6
1	501	Cambridge Bay	11,095,339	3,023,778	3.67	12,358,632	3,338,284	3.70	12,902,410	3,472,824	3.72	11.15	7.40	3.67	3.70
2	502	Gjoa Haven	5,423,948	1,478,146	3.67	5,619,357	1,520,955	3.69	5,850,890	1,577,156	3.71	11.13	7.39	3.67	3.70
3	503	Taloyoak	3,817,200	1,103,664	3.46	3,963,600	1,128,695	3.51	3,922,782	1,067,831	3.67	11.02	7.02	3.46	3.58
4	504	Kugaaruk	2,801,331	777,995	3.60	2,828,591	754,706	3.75	2,900,018	753,535	3.85	11.55	7.50	3.60	3.78
5	505	Kugluktuk	5,906,037	1,655,630	3.57	5,839,053	1,619,653	3.61	5,795,818	1,575,043	3.68	11.04	7.21	3.57	3.64
6	601	Rankin Inlet	17,777,180	4,760,405	3.73	18,112,704	4,827,388	3.75	18,490,110	4,883,739	3.79	11.36	7.50	3.73	3.77
7	602	Baker Lake	9,175,690	2,390,720	3.84	8,917,237	2,288,935	3.90	8,906,262	2,299,424	3.87	11.69	7.75	3.84	3.88
8	603	Arviat	8,381,227	2,520,031	3.33	8,660,728	2,297,554	3.77	8,635,350	2,352,527	3.67	11.31	7.34	3.33	3.66
9	604	Coral Harbour	3,552,000	1,056,608	3.36	3,525,200	1,039,361	3.39	3,540,800	1,045,437	3.39	10.18	6.77	3.36	3.39
10	605	Chesterfield Inlet	2,076,600	628,116	3.31	2,070,000	603,845	3.43	2,065,800	584,401	3.53	10.60	6.86	3.31	3.46
11	606	Whale Cove	1,975,320	539,547	3.66	1,844,299	524,296	3.52	1,930,820	511,783	3.77	11.32	7.32	3.52	3.69
12	607	Naujaat	3,794,423	1,033,376	3.67	4,115,205	1,123,973	3.66	4,314,782	1,122,761	3.84	11.53	7.34	3.66	3.76
13	701	Iqaluit	57,806,514	14,572,606	3.97	59,140,068	14,933,629	3.96	59,645,876	14,914,731	4.00	12.00	7.93	3.96	3.98
14	702	Pangnirtung	6,459,355	1,749,428	3.69	6,464,825	1,854,610	3.49	6,417,774	1,899,619	3.38	11.08	6.97	3.38	3.57
15	703	Cape Dorset	6,203,140	1,825,994	3.40	5,685,387	1,712,439	3.32	5,509,261	1,704,413	3.23	10.19	6.64	3.23	3.34
16	704	Resolute Bay	5,102,710	1,447,659	3.52	4,607,080	1,281,114	3.60	4,580,488	1,248,305	3.67	11.01	7.19	3.52	3.62
17	705	Pond Inlet	6,172,011	1,667,583	3.70	6,355,010	1,721,864	3.69	6,402,456	1,716,854	3.73	11.19	7.40	3.69	3.71
18	706	Igloolik	6,608,037	1,805,180	3.66	6,587,008	1,790,560	3.68	6,770,868	1,695,678	3.99	11.98	7.36	3.66	3.83
19	707	Hall Beach	3,317,573	952,594	3.48	3,376,287	924,632	3.65	3,374,250	919,207	3.67	11.01	7.30	3.48	3.63
20	708	Qikiqtarjuaq	2,809,200	802,913	3.50	2,776,200	800,131	3.47	2,764,868	786,504	3.52	10.55	7.00	3.47	3.50
21	709	Kimmirut	2,056,828	593,751	3.46	2,078,805	598,892	3.47	2,003,675	562,001	3.57	10.70	6.94	3.46	3.52
22	710	Arctic Bay	3,116,405	861,684	3.62	3,193,550	883,454	3.61	3,361,029	991,895	3.39	10.85	7.23	3.39	3.58
23	711	Clyde River	3,801,055	1,063,009	3.58	3,931,016	1,064,236	3.69	3,791,868	992,270	3.82	11.46	7.39	3.58	3.74
24	712	Grise Fiord	1,230,775	331,227	3.72	1,237,189	360,665	3.43	1,250,851	373,661	3.35	11.15	6.86	3.35	3.56
25	713	Sanikiluaq	3,624,377	980,127	3.70	3,718,389	985,418	3.77	3,837,362	1,009,453	3.80	11.40	7.55	3.70	3.78
26		**TOTAL**	**184,084,275**	**49,621,772**	**3.71**	**187,005,421**	**49,979,291**	**3.74**	**188,966,467**	**50,061,053**	**3.77**				**3.76**

Schedule 3.3:
Qulliq Energy Corporation 2018/19 General Rate Application Non Electric Revenues

(in thousands of dollars)

Line No.		2014/15 Forecast	2014/15 Actual	*Year over Year Change*	2015/16 Actual	*Year over Year Change*	2016/17 Preliminary Actual	*Year over Year Change*	2017/18 Forecast	*Year over Year Change*	2018/19 Forecast
1	Joint Use	677	675	0	675	(4)	672	5	677	-	677
2	Miscellaneous Charges	1,326	1,045	164	1,209	207	1,416	(306)	1,110	22	1,132
3	*Fees & Charges*	*587*	*668*	*143*	*811*	162	*973*	(223)	*750*	15	*765*
4	*Interest Income*	-	*16*	*11*	*28*	35	*63*	(63)	-	-	-
5	*Administration Fee - Housing Support*	*739*	*361*	*9*	*370*	10	*380*	(20)	*360*	7	*367*
6	*Other*	-	-	-	-	-	-	-	-	-	-
7	Time and Materials	1,648	591	34	625	99	724	(77)	647	92	739
10	**TOTAL**	3,650	2,311	199	2,510	303	2,812	(379)	2,434	114	2,548

4.0 REVENUE REQUIREMENT

4.1 INTRODUCTION

QEC's revenue requirement for 2018/19 reflects the forecast cost of providing service in the test year, including a fair return on equity. The revenue requirement is recovered by way of rates charged for electrical services, as well as non-electrical revenues [such as from pole rentals and other sources]. This section reviews QEC's revenue requirement for the test year 2018/19. Chapter 5 compares this revenue requirement to the revenues from existing rates (set out in Chapter 3) to calculate the shortfall in the 2018/19 test year.

Similar to previous GRA filings, there are four major components of QEC's revenue requirement:

- Operating and Maintenance costs, including, salaries and wages, supplies and services and travel and accommodation expenses;
- Production fuel and lubricants expenses;
- Amortization expense; and
- Return on Rate Base.

Table 4.1 summarizes the 2018/19 revenue requirement and indicates where more detailed explanation on each revenue requirement category is provided. Further details on the forecast 2018/19 revenue requirement and comparisons with other years are available in Schedule 4.1.

Table 4.1:
2018/19 Revenue Requirement ($000s)

	2018/19 Forecast
Non-Fuel O&M (section 4.3)	60,173
Production Fuel (section 4.4)	48,820
Amortization (section 4.5)	11,205
Return on Rate Base (section 4.6)	13,849
Revenue Requirement	**134,047**

This chapter is organized under the following headings:

- **Revenue Requirement Changes since the 2014/15 GRA:** Provides an overview of the key drivers of revenue requirement changes since the 2014/15 GRA.
- **Non-Fuel Operations and Maintenance Expenses:** Reviews non-production fuel expenses including salaries and wages, supplies and services and travel and accommodation.
- **Production Fuel and Lubricants:** Provides an overview of forecast fuel volumes and prices for the test year.
- **Amortization Expense:** Reviews fixed asset amortization expense and refinancing cost amortization.
- **Return on Rate Base:** Discusses the forecast capital structure as well as return on equity and cost of debt in the test year.

4.2 REVENUE REQUIREMENT CHANGES SINCE THE 2014/15 GRA

Table 4.2 provides a comparison of the 2014/15 and 2018/19 test year revenue requirements.

Table 4.2:
Revenue Requirement –
2014/15 GRA Forecast Compared to 2018/19 Forecast ($000s)

	2014/15 GRA Forecast	2018/19 Forecast
Non-Fuel O&M	53,459	60,173
Production Fuel	56,362	48,820
Amortization	8,893	11,205
Return on Rate Base	12,164	13,849
Revenue Requirement	**130,877**	**134,047**

The overall revenue requirement has increased by $3.170 million from the last GRA. Revenue requirement changes are driven by the following:

- Operating and Maintenance costs have increased by approximately $6.715 million since the last GRA, or 3.0% average annual growth;
- Fuel costs have decreased by $7.542 million or a 3.5% decrease per year on average;
- Fixed assets amortization costs have increased by $2.312 million or 5.9% average annual growth; and
- Return on rate base has increased by $1.685 million or 3.3% average annual growth.

These revenue requirement increases are offset to a degree by increases in electricity sales revenue. Further details are provided in the following sections.

4.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

QEC's forecasts for total operating and maintenance expenses for 2018/19 are set out in Table 4.3.

Table 4.3:
Non-Fuel O&M Expense –
2014/15 GRA Forecast Compared to 2018/19 ($000s)

	2014/15 GRA Forecast	2018/19 Forecast
Salaries and Wages	26,465	31,287
Supplies and Services, total	22,311	23,569
includes:		
Supplies and Services	22,201	23,459
Site Restoration expense	161	161
Corporate donations	(50)	(50)
Travel and Accommodation	4,682	5,317
Total Non-Fuel O&M Expense	**53,459**	**60,173**

Overall, the Corporation's non-fuel 2018/19 Operation and Maintenance (O&M) expenses have increased by $6.715 million since the 2014/15 GRA or an average annual increase of 3.0%. Average annual inflation for Nunavut for the period from April 2014 to April 2017 was 1.9%[6], therefore in real terms, the average annual increase of non-fuel O&M expenses is about 1%. Overall, the changes in QEC's O&M expense reflect the

[6] Source: Statistics Canada, CANSIM table 326-0020, data for Iqaluit, Nunavut. The 1.9% is average of 3-year fiscal year CPI increase (2.0% increase in April 2015 over April 2014; 2.3% increase in April 2016 over April 2015; and 1.5% increase in April 2017 over April 2016). http://www5.statcan.gc.ca/cansim/a47 [accessed on September 12, 2017].

Corporation's priorities on safety, reliability, efficiency and responsiveness to stakeholder concerns.

4.3.1 SALARIES AND WAGES

Forecast salaries and wages expense of $31.287 million for 2018/19 reflect a number of strategic priorities for the Corporation. The $4.822 million increase in salaries and wages expense compared to the 2014/15 GRA forecast reflects:

- Cost of living increases consistent with the Corporation's collective agreements;
- Annual step (merit) increments for employees; and
- Changes to staff complement in response to a number of strategic priorities for the Corporation.

For positions covered by the Corporation's collective agreement, the average annual increase in hourly rates was 1.5% for each of 2015 and 2016 (calendar years). The compounded increase is 3.0% over the two years.[7] Corporate wide, average annual salaries and wages per Full Time Equivalent positions (FTE) are forecast to increase from $141,000 in the 2014/15 GRA to approximately $169,000 in 2018/19, or an average annual increase of 4.7%, including both cost of living and merit increases.

[7] Source: Collective Agreement between Qulliq Energy Corporation and Nunavut Employees Union. Expires December 31, 2016. At the time of the GRA application no new collective agreement was signed. http://www.gov.nu.ca/sites/default/files/files/Finance/CollectiveAgreements/qec_gn_neu_ca_ends_dec_31_2016_-_english_final.pdf [accessed on April 27, 2017].

In order to continue to provide safe and reliable service the Corporation changed its staff complement in response to a number of strategic priorities. Overall, in the 2014/15 GRA the forecast FTE complement was 204. For the 2018/19 test year the number of FTEs is forecast to be 206 or a net increase of 2 FTEs.

The new additions are in the Iqaluit corporate office [Manager, Policy and Planning and Policy Analyst]. The new FTE additions were required to for coordinating and developing strategic and corporate plans, tracking implementation and measuring performance.

For the 2018/19 test year the Corporation is forecasting a vacancy rate of 10.2%. This is consistent with the vacancy rate used in the 2014/15 GRA.[8] The forecast is based on the actual results achieved in 2016/17 and consistent with the Corporation's 2016-2020 Corporate Plan[9] which established strategic goals to improve employee retention and reduce vacancies[10] compared to previous actual years. The Corporation's objectives include increasing local hiring, increasing Inuit employment and reducing turnover by promoting training and retention.

4.3.2 SUPPLIES AND SERVICES

Supplies and services expense represents the cost of maintaining the plants and equipment including materials, freight, contractors, professional development and administration. Forecast costs for supplies and services are $23.459 million for 2018/19.

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[8] In the 2014/15 GRA the URRC recommended a 10% vacancy rate for the 2014/15 GRA.
[9] Available on website of Legislative Assembly of Nunavut. http://assembly.nu.ca/sites/default/files/TD%20148-4(3)%20EN%20Qulliq%20Energy%20Corporation%20Corporate%20Plan%202016-2020.pdf [accessed on September 12, 2017].
[10] The actual vacancies for 2014/15 were at 12.8% and for 2015/16 at 14.0%.

Compared to 2014/15 GRA levels, this reflects an increase of $1.258 million, or an average increase of 1.4% per year, within the range of average annual inflation increases of 1.9%.

4.3.3 TRAVEL AND ACCOMMODATION

Travel and Accommodation expense includes all of the costs associated with travel, meals and accommodation for operational, professional development and employee medical needs. Forecast travel costs of $5.317 million in 2018/19 represent an increase of $0.635 million compared to the 2014/15 GRA forecasts or about 3.2% average annual increase.

This increase represents inflationary increases as well as the following:

- **The majority of the increase is due to increased Medical Travel expenses ($0.512 million over 2014/15 GRA forecast).** As indicated during the 2014/15 GRA, the Corporation's medical travel policy covers travel, accommodation, meal and incidental expenses for employees and dependents of employees who require medical treatment which is not available in their community of employment.[11] The increase in this expense category is driven by the increased number of employees and is in line with the actual expenses in recent years. The actual expenses in recent years have been approximately $1.018 million to $1.210 million compared to the 2014/15 GRA forecast of $0.712 million.

[11] QEC 2014/15 General Rate Application, p. 4-9.

- **Relocation Travel/Meal/Freight ($0.195 million over 2014/15 GRA):** The increase in relocation related expenses reflects in part the Corporation's growing workforce and requirements related to staff turnover. The budget for this expense category is consistent with actual spending in previous years.

The Corporation is forecasting decreases in business travel and accommodation costs as well as reductions in training travel which offsets the increases in other travel cost categories.

4.4 PRODUCTION FUEL

QEC's actual and forecast production fuel costs are set out in Schedules 4.2.1 through 4.2.5. Forecast production fuel expenses in 2018/19 are $7.542 million lower relative to the 2014/15 GRA.

The change in forecast fuel reflects the following:

- **Load Forecast ($1.859 million increase over 2014/15 GRA forecast at 2014/15 prices and fuel efficiencies).** The increased sales noted in Chapter 3 result in increased generation fuel requirements.

- **Fuel Price Change ($8.703 million reduction from 2014/15 GRA forecast).** Average 2018/19 fuel prices are forecast to be $0.93/litre, a decrease relative to 2014/15 average fuel prices of $1.10/litre. Further details on QEC's fuel price forecasts for 2018/19 are provided below.

- **Fuel Efficiency Change ($0.677 million reduction from 2014/15 GRA forecast).** Fuel efficiencies have improved from an average of 3.71 litres/kWh in the 2014/15 GRA to an average of 3.76 litres/kWh. These improvements have reduced the fuel volume by about 0.730 million litres which reduced overall fuel cost at the 2018/19 forecast fuel prices by $0.677 million as compared to the 2014/15 GRA forecast.

- **Lube Cost ($0.021 million reduction from 2014/15 GRA forecast).** 2018/19 lube costs are also slightly lower than forecast at the time of the 2014/15 GRA.

Table 4.4:
Generation, Fuel Consumption and Fuel Cost –
2014/15 GRA Forecast Compared to 2018/19 Forecast

	2014/15 GRA Forecast	2018/19 Forecast	Change	Average Annual Growth
Generation (MWh)	**187,160**	**193,338**		**0.8%**
2014/15 GRA Fuel efficiency (kWh/L)	3.71	3.71		
Fuel Volume at 2014/15 efficiency (L 000)	**50,421**	**52,083**		**0.8%**
2014/15 GRA average fuel price ($/L)	*1.10*	*1.10*		
Fuel cost at 2014/15 GRA fuel price and efficiency	**55,510**	**57,368**	**1,859**	**0.8%**
2018/19 forecast average fuel price ($/L)		*0.93*		
Fuel price change from 2014/15 GRA ($/L)		*-0.17*		
Cost change due to fuel price ($000)		**-8,703**	**-8,703**	
Fuel efficiency (KWh/L)		*3.76*		
Cost change due to fuel efficiency ($000)		**-677**	**-677**	
Lube Cost ($000)	**852**	**831**	**-21**	
Total fuel and lubricants ($000)	**56,362**	**48,820**	**-7,542**	**-3.5%**

Fuel Price Forecast

QEC purchases fuel through the Petroleum Products Division (PPD) of the Department of Community and Government Services (CGS) of Government of Nunavut. Approximately 35% of QEC's forecast generation fuel requirements are supplied through bulk fuel purchases in seven communities. The remaining 65% is purchased at nominated fuel prices set by the Territorial government. In setting the nominated fuel prices the GN considers both market prices and other policy objectives.[12] Nominated fuel prices are typically adjusted in January of each year.

Fuel costs represent approximately 36% of QEC's total 2018/19 revenue requirement. QEC's current fuel prices are substantially lower than the fuel prices included in the 2014/15 GRA. The July 2017 weighted average fuel price is about 18% lower compared to 2014/15 GRA weighted average fuel prices as illustrated in QEC's September 2017 FSR application. QEC captures differences between actual fuel prices and GRA approved fuel prices in the FSR. However, the Nunavut Electricity Subsidy Program (NESP) does not subsidize fuel stabilization riders, therefore, if fuel prices built into base energy rates are too low, customers pay the full amount of future fuel riders associated with higher fuel prices compared to the GRA forecast prices. Carbon pricing policies may place upward pressure on future fuel prices. The potential impact of these changes is not known at this time.

[12] For example, the nominated fuel prices announced effective January 30, 2017 are separated into three zones and fuel prices are the same within the zone regardless of community distance from fuel delivery point.

In preparing the 2018/19 fuel price forecast for the GRA, the Corporation notes that 2017 summer fuel prices are somewhat higher than summer 2016 prices. Oil futures markets suggest that further price increases may occur in summer 2018. These changes could impact both bulk and nominated fuel prices.

Based on these considerations, QEC prepared a GRA fuel price forecast that reflects the following:

- Summer 2017 bulk fuel prices based on information provided by the Petroleum Products Division of the Department of Community and Government Services (C&GS) of Government of Nunavut.
- 2018 forecast nominated fuel prices are based on the actual fuel prices announced by Government of Nunavut effective January 30, 2017.
- Summer 2018 bulk fuel prices are forecast to increase an additional 3% over summer 2017 prices.[13]
- 2019 nominated fuel prices anticipated to take effect in January 2019 are forecast to be about 3% higher compared to the actual fuel prices announced by Government of Nunavut effective January 30, 2017.

Average GRA fuel prices reflect a forecast of fuel inventory and mixture of bulk and nominated fuel consistent with previous operating experience.

[13] The forecast increases are based on QEC's analysis of Montreal Brent futures.

4.5 AMORTIZATION EXPENSE

Amortization expense comprises the sum of fixed asset amortization, amortization of financing costs as well as a provision for loss on disposals of assets.

The increase in amortization expense reflects growth in fixed assets as detailed in Section 6.2. Financing cost amortization of $0.249 million is included in the revenue requirement in accordance with the URRC Report to the responsible Minister on QEC's 2004/05 GRA.[14]

Table 4.5 shows changes to amortization expense from 2014/15 to the 2018/19 forecast. Changes reflect a number of factors including:

- **Fixed Asset Amortization Rate Changes:** QEC commissioned a new amortization study. The major changes include longer expected life for some assets. The new amortization rates reduce the 2018/19 test year amortization expense by about $1.287 million.
- **Provision for Loss on Disposals:** The Corporation uses an asset by asset amortization approach to calculate amortization expense. Under this approach no asset is over amortized and at the time of retirement of the asset QEC incurs a net loss equal to the unamortized portion of the original cost of the asset. QEC has included a provision for loss on disposals as part of the amortization expense based on the average for the last three years.

[14] URRC Report to the Minister Responsible for the Qulliq Energy Corporation, February 18, 2005. Schedule B-1.

- **Asset Retirement Obligation:** With the removal of the provision for net salvage from amortization expense, the Corporation considered the need to include an Asset Retirement Obligation (ARO) related to potential environmental liabilities. Upon consideration, the Corporation determined not to include a provision for an ARO related to environmental liabilities as part of amortization expense for the current application.

Table 4.5:
Amortization Expense –
2014/15 GRA Forecast Compared to 2018/19 Forecast ($000s)

	2014/15 Forecast	2018/19 Forecast
Fixed Asset Amortization	8,644	10,549
Loss on Disposal of Assets	-	407
Add: Financing Cost Amortization	249	249
Total	**8,893**	**11,205**

4.6 RETURN ON RATE BASE

Return on ratebase represents the weighted average cost of long-term debt, equity and no-cost capital required to finance the Corporation's rate base. Changes to return on rate base occur as a result of changes to the Corporation's net plant in service, changes to the mix of debt and equity in the Corporation's capital structure and changes to the relative costs of debt and equity.

The Corporation's capital structure, rate base and return on rate base for 2018/19 compared to the 2014/15 GRA test year are shown in Table 4.6.

Table 4.6:
Return on Rate Base –
2014/15 GRA Forecast Compared to 2018/19 Forecast ($000s)

	2014/15 GRA Forecast	2018/19 Forecast
Mid-Year Net Plant in Service	168,524	221,947
Working Capital	20,205	27,326
Mid Year Rate Base	**188,729**	**249,274**
Average Rate of Return on Rate Base	6.44%	5.56%
Return on Rate Base	**12,164**	**13,849**

Return on rate base is forecast to increase by $1.685 million relative to the 2014/15 test year. This change relates to increases in mid-year rate base with an offsetting reduction in the average rate of return on rate base. Since the last GRA, significant investment in new infrastructure and re-investment in existing infrastructure has been undertaken to ensure the Corporation can continue to meet load growth in a safe and reliable manner. The forecast growth in net mid-year rate base from the 2014/15 test year to the 2018/19 test year is $60.545 million. These increases are partially offset by a reduction in the overall cost of capital. The average rate of return on ratebase is forecast to decrease from 6.44% in the 2014/15 GRA to 5.56% in the 2018/19 test year (which reduces return on rate base by about $2.194 million). This decrease reflects the decrease in both average cost of long-term debt and return on equity (ROE). Calculation of the return on rate base is detailed in Schedule 4.4.

4.6.1 CAPITAL STRUCTURE

Section 25 of the Qulliq Energy Corporation Act requires the Corporation's borrowings not to exceed three times its equity at any time. In its Report 2011-01 to the Minister respecting QEC's 2010/11 GRA, the URRC considered a 40% equity ratio to be appropriate for the determination of a fair return on rate base in 2010/11.[15] QEC's proposed capital structure shown in Schedule 4.4 reflects a deemed 40% equity ratio consistent with the URRC Report 2011-01 as well as QEC's 2014/15 GRA and the URRC Report 2014-04. A continuity schedule of the Corporation's capitalization is provided in Schedule 4.5.

4.6.2 AVERAGE COST OF LONG-TERM DEBT

The forecast average cost of long-term debt decreased from 4.81% in the 2014/15 GRA to 3.37% for 2018/19. The reduction in average cost of long-term debt reflects overall lower interest rates for new debt. In the 2017/18 and 2018/19 fiscal years the Corporation forecasts it will take on new long-term debt of $77.366 million and $24.999 million, respectively, at an interest rate of 2.95%. This interest rate is based on the Bank of Canada business prime rate.[16] The most recent actual long-term debt the Corporation secured has an interest rate of prime minus 0.5% per annum. However, the Corporation expects that the cost of debt for the forecast years will increase.[17] This expectation is also consistent with the recent increase of the interest rate announced by the Bank of Canada. Schedule 4.6 shows the calculation of the average cost of long-term debt consistent with

[15] Page 34, URRC Report 2011-01 to the Minister responsible for Qulliq Energy Corporation, March 2, 2011.
[16] Bank of Canada, http://www.bankofcanada.ca/rates/daily-digest/ [accessed on April 19, 2017].
[17] For example, NTPC in its 2016-19 GRA forecasted $50 million new in 2016/17 with a 30 year term and interest rate of 4.00%. NTPC notes that the rate is based on long Canada yields at March 2016 plus a credit spread of between 1.50% and 2.00% [Information Request TGC.NTPC-20].

the URRC recommendation in the URRC Report 2014-04 based on mid-year balance of the debt.

4.6.3 NO COST CAPITAL

No cost capital includes the notional hearing cost reserve account balance.[18] The hearing cost reserve account reflects the combined Hearing and Reserve for Injuries and Damages (RFID) balances, reduced by the hearing costs charged to the account. Hearing costs for 2014/15 to 2016/17 are recorded on an actual basis and forecast 2017/18 expenses reflect the expected cost of the current rate application review process.

4.6.4 RETURN ON EQUITY

For the 2014/15 test year, the URRC recommended approval of a 9.0% return on equity (ROE). In the 2014/15 GRA application the Corporation noted that it operates in a harsher environment than other Canadian utilities due to the isolated nature of its communities (i.e. no road or rail interconnections with southern jurisdictions); the smaller size of its communities and the lack of access to hydro-electric generation sources. The Corporation also noted that it believes its ROE should at a minimum be consistent with the levels approved for NUL(NWT) at 9.30%,[19] and that there likely could be an argument that its business risks would support a higher ROE.

[18] In 2014/15 GRA QEC also had GN no-cost loan as no cost capital. The last payment for the loan was made in 2015/16 fiscal year with the balance for the 2018/19 test year at zero.

[19] Northwest Territories Public Utilities Board. Decision 17-2011. Page 5 of Appendix A.

In the most recent 2014/15 GRA for NUL (NWT) the Northwest Territories Public Utilities Board (NWT PUB) by its Decision 9-2014 approved a ROE based on the Alberta Utilities Commission (AUC) Generic Cost of Capital at 8.75%[20] plus 35 basis points to total of 9.10% as a placeholder for both the 2014 and 2015 test years.

Since the time of the NUL (NWT) 2014/15 GRA, the AUC in its Decision 20622-D01-2016[21] from October 7, 2016 approved a generic ROE for 2017 at 8.5% which is 25 basis points lower compared to the last approved generic interim ROE at 8.75%.

QEC's proposed ROE for the 2018/19 test year is 8.85% based on the most recent approved generic ROE at 8.50% plus 35 basis points consistent with the most recently approved ROE approach for NUL(NWT).

QEC also reviewed the ROE for the other northern utilities:

- In Decision 1-2013 the NWT PUB approved NTPC's requested ROE of 8.50% for each of the 2012/13 and 2013/14 test years.[22] NTPC in its 2016/19 GRA also requested to maintain the 8.50% ROE. QEC's operating environment is harsher compared to NPTC with smaller communities and no hydro-electric generation. Based on this, the Corporation does not consider that the latest approved ROE for NTPC reasonably reflects QEC's return on equity requirements.

[20] In its Decision 2011-474 AUC approved a "benchmark" ROE at 8.75% for 2011 and 2012 on final basis, and on an interim basis for 2013. In its Decision 2013-459 AUC approved ROE at 8.75% for 2014 on interim basis. http://www.auc.ab.ca/applications/decisions/Decisions/2013/2013-459.pdf [accessed on December 14, 2016].
[21] Available at http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20622-D01-2016.pdf [accessed on July 19, 2017].
[22] Northwest Territories Public Utilities Board. Decision 1-2013. Page 62.

- In its Order 2017-01 the Yukon Utilities Board (YUB) approved an ROE of 8.75% for ATCO Electric Yukon (AEY) for the 2016-2017 test years based on the British Columbia Utilities Commission (BCUC) benchmark rate approved by in Order G-75-13. In its 2016-17 GRA AEY requested a ROE at 9.35% based on the BCUC benchmark rate of 8.75% plus a 60 basis point risk premium.[23] QEC's operating environment is harsher compared to AEY which mostly operates as a distribution company with a small hydro generation facility.

- In its Order 2013-01 the YUB approved a ROE of 8.25% for Yukon Energy Corporation (YEC) for the 2012 and 2013 test years based on the BCUC benchmark rate of 8.75% less 50 basis points as per direction from Yukon Government Order-in-Council 1995/90. In its 2017-18 GRA YEC requested ROE at 8.82% based on BCUC benchmark rate at 8.75% less 50 basis points as per direction noted above plus 57 basis points risk premium.[24] QEC's operating environment is harsher compared to YEC where more than 99% of the total generation is from hydro sources with transmission interconnections between many communities.

[23] AEY 2016-17 GRA, page 8-2. YUB Order 2017-01, paragraph 182. Available at http://yukonutilitiesboard.yk.ca/proceedings/yecl-2016-17-general-rate-application/ [accessed on September 12, 2017].

[24] YEC 2017-18 GRA, page 3-23. http://yukonutilitiesboard.yk.ca/pdf/YEC_2017-18_GRA/YEC_2017-2018_General_Rate_Application_FINAL_WEB_VERSION.pdf [accessed on September 12, 2017].

Schedule 4.1:
Qulliq Energy Corporation 2018/19 General Rate Application
Revenue Requirement ($000)

Line No.		2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast
1	**Operation & Maintenance Expense**						
2	Salaries and Wages	$ 26,465	$ 29,611	$ 30,386	$ 33,273	$ 30,376	$ 31,287
3	Supplies and Services	22,201	19,618	21,526	24,740	22,999	23,459
4	Site Restoration Expense	161	-	-	-	161	161
5	Travel and Accommodation	4,682	4,732	4,391	4,708	5,213	5,317
6	**Non-Fuel Operation & Maintenance Expense**	**53,509**	**53,961**	**56,303**	**62,721**	**58,748**	**60,223**
7	Less: Corporate Donations	(50)	(41)	(51)	(14)	(50)	(50)
8	**Non-Fuel Operation & Maintenance Expense for GRA**	**53,459**	**53,920**	**56,252**	**62,707**	**58,698**	**60,173**
9	**Fuel and Lubricants Expense**	**56,362**	**56,077**	**55,318**	**47,575**	**48,051**	**48,820**
10	**Amortization**						
11	Fixed Asset Amortization	8,644	9,365	10,788	11,703	9,313	10,549
12	Loss on Disposal of Assets		26	668	528	407	407
13	Add: Financing Cost Amortization	249	249	249	249	249	249
14	**Total Net Amortization Expense**	**8,893**	**9,640**	**11,705**	**12,480**	**9,970**	**11,205**
15	**Total Return on Rate Base**	**12,164**	**11,236**	**1,911**	**15,419**	**11,861**	**13,849**
16	**Total Revenue Requirement**	**130,877**	**130,872**	**125,186**	**138,182**	**128,580**	**134,047**

Schedule 4.2.1:
Qulliq Energy Corporation 2018/19 General Rate Application
2014/15 Actual Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	ACTUAL GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL CONSUMPTION (000 L)	AVERAGE ANNUAL FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	11,095	3.67	3,024	1.11	3,362	38	3,400
2	502	Gjoa Haven	5,424	3.67	1,478	1.28	1,889	25	1,913
3	503	Taloyoak	3,817	3.46	1,104	1.29	1,421	27	1,448
4	504	Kugaaruk	2,801	3.60	778	1.31	1,020	11	1,031
5	505	Kugluktuk	5,906	3.57	1,656	1.12	1,848	19	1,866
6	601	Rankin Inlet	17,777	3.73	4,760	1.07	5,106	148	5,254
7	602	Baker Lake	9,176	3.84	2,391	1.16	2,764	15	2,778
8	603	Arviat	8,381	3.33	2,520	1.07	2,704	18	2,722
9	604	Coral Harbour	3,552	3.36	1,057	1.07	1,126	18	1,144
10	605	Chesterfield Inlet	2,077	3.31	628	1.20	754	10	763
11	606	Whale Cove	1,975	3.66	540	1.16	625	17	641
12	607	Naujaat	3,794	3.67	1,033	1.14	1,181	26	1,207
13	701	Iqaluit	57,807	3.97	14,573	1.16	16,944	260	17,204
14	702	Pangnirtung	6,459	3.69	1,749	0.98	1,709	23	1,733
15	703	Cape Dorset	6,203	3.40	1,826	0.98	1,783	46	1,828
16	704	Resolute Bay	5,103	3.52	1,448	1.06	1,534	26	1,560
17	705	Pond Inlet	6,172	3.70	1,668	0.99	1,651	138	1,789
18	706	Igloolik	6,608	3.66	1,805	1.02	1,842	51	1,893
19	707	Hall Beach	3,318	3.48	953	1.02	973	26	999
20	708	Qikiqtarjuaq	2,809	3.50	803	0.98	784	17	801
21	709	Kimmirut	2,057	3.46	594	0.99	585	16	601
22	710	Arctic Bay	3,116	3.62	862	1.00	864	9	872
23	711	Clyde River	3,801	3.58	1,063	1.03	1,095	31	1,126
24	712	Grise Fiord	1,231	3.72	331	1.10	365	7	372
25	713	Sanikiluaq	3,624	3.70	980	1.15	1,124	7	1,131
26		**TOTAL**	**184,084**	**3.71**	**49,622**	**1.11**	**55,051**	**1027**	**56,077**

Schedule 4.2.2:
Qulliq Energy Corporation 2018/19 General Rate Application
2015/16 Actual Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	ACTUAL GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL CONSUMPTION (000 L)	AVERAGE ANNUAL FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	12,359	3.70	3,338	1.10	3,677	24	3,701
2	502	Gjoa Haven	5,619	3.69	1,521	1.33	2,026	22	2,049
3	503	Taloyoak	3,964	3.51	1,129	1.15	1,294	8	1,302
4	504	Kugaaruk	2,829	3.75	755	1.41	1,067	14	1,081
5	505	Kugluktuk	5,839	3.61	1,620	0.89	1,449	21	1,470
6	601	Rankin Inlet	18,113	3.75	4,827	1.02	4,941	74	5,014
7	602	Baker Lake	8,917	3.90	2,289	1.07	2,457	16	2,473
8	603	Arviat	8,661	3.77	2,298	0.90	2,079	46	2,125
9	604	Coral Harbour	3,525	3.39	1,039	1.16	1,201	9	1,210
10	605	Chesterfield Inlet	2,070	3.43	604	1.24	746	6	752
11	606	Whale Cove	1,844	3.52	524	0.84	443	12	455
12	607	Naujaat	4,115	3.66	1,124	1.20	1,349	17	1,366
13	701	Iqaluit	59,140	3.96	14,934	1.15	17,162	184	17,346
14	702	Pangnirtung	6,465	3.49	1,855	0.91	1,683	4	1,687
15	703	Cape Dorset	5,685	3.32	1,712	0.92	1,582	26	1,609
16	704	Resolute Bay	4,607	3.60	1,281	0.94	1,207	17	1,224
17	705	Pond Inlet	6,355	3.69	1,722	0.92	1,583	22	1,605
18	706	Igloolik	6,587	3.68	1,791	0.95	1,708	21	1,729
19	707	Hall Beach	3,376	3.65	925	1.03	952	15	967
20	708	Qikiqtarjuaq	2,776	3.47	800	0.93	742	13	755
21	709	Kimmirut	2,079	3.47	599	0.94	563	10	573
22	710	Arctic Bay	3,194	3.61	883	0.91	804	19	823
23	711	Clyde River	3,931	3.69	1,064	0.97	1,029	18	1,047
24	712	Grise Fiord	1,237	3.43	361	1.04	375	5	381
25	713	Sanikiluaq	3,718	3.77	985	1.08	1,060	12	1,072
26		Year-end adjustments					1,503		1,503
27		**TOTAL**	**187,005**	**3.74**	**49,979**	**1.06**	**54,683**	**636**	**55,318**

Schedule 4.2.3:
Qulliq Energy Corporation 2018/19 General Rate Application
2016/17 Preliminary Actual Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL CONSUMPTION (000 L)	AVERAGE ANNUAL FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	12,902	3.72	3,473	0.94	3,273	71	3,344
2	502	Gjoa Haven	5,851	3.71	1,577	1.13	1,784	49	1,833
3	503	Taloyoak	3,923	3.67	1,068	1.18	1,262	14	1,276
4	504	Kugaaruk	2,900	3.85	754	1.18	888	5	893
5	505	Kugluktuk	5,796	3.68	1,575	0.89	1,406	17	1,423
6	601	Rankin Inlet	18,490	3.79	4,884	0.81	3,975	80	4,055
7	602	Baker Lake	8,906	3.87	2,299	1.02	2,351	19	2,370
8	603	Arviat	8,635	3.67	2,353	0.81	1,901	57	1,958
9	604	Coral Harbour	3,541	3.39	1,045	1.01	1,060	16	1,076
10	605	Chesterfield Inlet	2,066	3.53	584	1.11	647	4	652
11	606	Whale Cove	1,931	3.77	512	1.01	515	7	522
12	607	Naujaat	4,315	3.84	1,123	1.00	1,120	13	1,133
13	701	Iqaluit	59,646	4.00	14,915	0.95	14,102	299	14,401
14	702	Pangnirtung	6,418	3.38	1,900	0.88	1,678	8	1,686
15	703	Cape Dorset	5,509	3.23	1,704	0.87	1,485	29	1,514
16	704	Resolute Bay	4,580	3.67	1,248	0.95	1,180	14	1,194
17	705	Pond Inlet	6,402	3.73	1,717	0.89	1,526	26	1,552
18	706	Igloolik	6,771	3.99	1,696	0.91	1,539	18	1,557
19	707	Hall Beach	3,374	3.67	919	0.91	835	17	852
20	708	Qikiqtarjuaq	2,765	3.52	787	0.87	684	8	692
21	709	Kimmirut	2,004	3.57	562	0.88	496	16	513
22	710	Arctic Bay	3,361	3.39	992	0.89	886	14	900
23	711	Clyde River	3,792	3.82	992	0.77	760	9	769
24	712	Grise Fiord	1,251	3.35	374	0.97	364	4	368
25	713	Sanikiluaq	3,837	3.80	1,009	1.02	1,029	13	1,042
26		**TOTAL**	**188,966**	**3.77**	**50,061**	**0.93**	**46,744**	**831**	**47,575**

Schedule 4.2.4:
Qulliq Energy Corporation 2018/19 General Rate Application
2017/18 Forecast Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL REQUIRED (000 L)	FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	13,204	3.70	3,569	0.93	3,332	71	3,403
2	502	Gjoa Haven	5,813	3.70	1,571	1.02	1,602	49	1,652
3	503	Taloyoak	3,989	3.58	1,114	1.02	1,136	14	1,150
4	504	Kugaaruk	2,990	3.78	791	1.02	807	5	811
5	505	Kugluktuk	6,013	3.64	1,652	0.94	1,553	17	1,571
6	601	Rankin Inlet	18,379	3.77	4,875	0.86	4,198	80	4,279
7	602	Baker Lake	8,980	3.88	2,314	0.96	2,215	19	2,235
8	603	Arviat	9,268	3.66	2,532	0.87	2,201	57	2,258
9	604	Coral Harbour	3,659	3.39	1,079	0.96	1,033	16	1,049
10	605	Chesterfield Inlet	2,099	3.46	607	0.96	581	4	585
11	606	Whale Cove	1,998	3.69	541	0.96	518	7	525
12	607	Naujaat	4,269	3.76	1,135	0.93	1,050	13	1,064
13	701	Iqaluit	60,219	3.98	15,130	0.91	13,726	299	14,025
14	702	Pangnirtung	6,451	3.57	1,807	0.95	1,716	8	1,724
15	703	Cape Dorset	5,819	3.34	1,742	0.95	1,654	29	1,684
16	704	Resolute Bay	4,584	3.62	1,266	0.95	1,202	14	1,216
17	705	Pond Inlet	6,656	3.71	1,794	0.95	1,704	26	1,730
18	706	Igloolik	6,891	3.83	1,799	0.95	1,708	18	1,726
19	707	Hall Beach	3,374	3.63	930	0.95	883	17	900
20	708	Qikiqtarjuaq	2,847	3.50	813	0.95	772	8	781
21	709	Kimmirut	2,049	3.52	582	0.95	553	16	569
22	710	Arctic Bay	3,263	3.58	911	0.95	865	14	880
23	711	Clyde River	3,863	3.74	1,033	0.88	912	9	921
24	712	Grise Fiord	1,212	3.56	341	0.95	323	4	328
25	713	Sanikiluaq	3,843	3.78	1,017	0.96	973	13	986
26		**TOTAL**	**191,736**	**3.76**	**50,948**	**0.93**	**47,220**	**831**	**48,051**

Schedule 4.2.5:
Qulliq Energy Corporation 2018/19 General Rate Application
2018/19 Forecast Production Fuel Cost

Line No.	PLANT No.	PLANT NAME	FORECAST GENERATION (MWh)	PLANT EFFICIENCY (kWh/L)	FUEL REQUIRED (000 L)	FUEL PRICE ($/L)	FUEL COST (000$)	LUBE COST (000$)	FUEL & LUBE COST (000$)
1	501	Cambridge Bay	13,228	3.70	3,575	0.95	3,414	71	3,485
2	502	Gjoa Haven	5,953	3.70	1,609	1.00	1,613	49	1,662
3	503	Taloyoak	4,051	3.58	1,131	1.00	1,136	14	1,150
4	504	Kugaaruk	3,029	3.78	801	1.00	803	5	808
5	505	Kugluktuk	5,980	3.64	1,643	0.96	1,579	17	1,596
6	601	Rankin Inlet	18,382	3.77	4,876	0.90	4,368	80	4,448
7	602	Baker Lake	8,898	3.88	2,293	0.94	2,160	19	2,179
8	603	Arviat	9,286	3.66	2,537	0.90	2,276	57	2,333
9	604	Coral Harbour	3,658	3.39	1,079	0.94	1,016	16	1,032
10	605	Chesterfield Inlet	2,086	3.46	603	0.94	568	4	573
11	606	Whale Cove	1,960	3.69	531	0.94	500	7	508
12	607	Naujaat	4,391	3.76	1,168	0.93	1,091	13	1,104
13	701	Iqaluit	61,456	3.98	15,441	0.93	14,345	299	14,645
14	702	Pangnirtung	6,467	3.57	1,811	0.93	1,693	8	1,701
15	703	Cape Dorset	5,724	3.34	1,714	0.94	1,605	29	1,634
16	704	Resolute Bay	4,511	3.62	1,246	0.93	1,164	14	1,178
17	705	Pond Inlet	6,713	3.71	1,809	0.93	1,689	26	1,715
18	706	Igloolik	6,910	3.83	1,804	0.93	1,684	18	1,702
19	707	Hall Beach	3,441	3.63	948	0.93	886	17	903
20	708	Qikiqtarjuaq	2,867	3.50	819	0.93	765	8	774
21	709	Kimmirut	2,022	3.52	574	0.94	537	16	554
22	710	Arctic Bay	3,331	3.58	930	0.93	869	14	883
23	711	Clyde River	3,920	3.74	1,048	0.90	947	9	956
24	712	Grise Fiord	1,193	3.56	335	0.93	313	4	318
25	713	Sanikiluaq	3,881	3.78	1,027	0.94	966	13	979
26		**TOTAL**	**193,338**	**3.76**	**51,355**	**0.93**	**47,989**	**831**	**48,820**

Schedule 4.3:
Qulliq Energy Corporation 2018/19 General Rate Application
Amortization Provision by Functions ($000)

Line No.	Amortization Provision by Major FERC Category	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast
1	**Diesel Plant**						
2	Amortization	6,919	7,699	8,864	9,751	7,862	8,936
3	Add (Less): Adjustments		0	0	0	0	0
4	Total Diesel Plant Amortization	6,919	7,699	8,864	9,751	7,862	8,936
5	**Distribution Plant**						
6	Amortization	603	790	883	890	940	1,002
7	Add (Less): Adjustments		0	0	0	0	0
8	Total Distribution Plant Amortization	603	790	883	890	940	1,002
9	**General Plant**						
10	Amortization	1,172	949	1,107	1,133	1,176	1,275
11	Add (Less): Adjustments		0	0	0	0	0
12	Total General Plant Amortization	1,172	949	1,107	1,133	1,176	1,275
13	**Energy Utilization Group**						
14	Amortization	28	4	11	7	6	6
15	Add (Less): Adjustments		0	0	0	0	0
16	Total EUG Amortization	28	4	11	7	6	6
17	**Insurance Proceeds**						
18	Amortization	-78	-78	-78	-78	-671	-671
19	Add (Less): Adjustments		0	0	0	0	0
20	Total Insurance Proceeds Amortization	-78	-78	-78	-78	-671	-671
21	**Total Rate Base Amortization**	**8,644**	**9,365**	**10,788**	**11,703**	**9,313**	**10,549**
22	Add: Financing Cost Amortization	249	249	249	249	249	249
23	Add: Loss on Disposal of Assets		26	668	528	407	407
24	**Total Amortization**	**8,893**	**9,640**	**11,705**	**12,480**	**9,970**	**11,205**

Note:

1. Amortization expenses are net of Residual Heat.
2. Amortization expenses reflect exclusion of the disallowed amount of $1.745 million from utility plant in service per the URRC directive from the Final Report on QEC's 2004/05 GRA.
3. Generation Plant Amortization expense reflects exclusion of the amount for Government of Nunavut contributions.
4. Distribution Plant Amortization expense reflects exclusion of the amount for customer contributions.

Schedule 4.4:
Qulliq Energy Corporation 2018/19 General Rate Application
Return on Rate Base – Mid year ($000)

Line No.		Mid-Year Capitalization	Deemed Mid-Year Capital Ratios [1]	Mid-Year Rate Base	Mid-Year Cost Rate	Return
	2014/15 GRA Forecast					
1	Common Equity	104,814	40.00%	75,492	9.00%	6,794
2	Long Term Debt	128,176	59.13%	111,589	4.81%	5,369
3	No Cost Capital	2,052	0.87%	1,648	0.00%	0
4	**TOTAL**	**$ 235,042**	**100.00%**	**$ 188,729**	**6.637%**	**$ 12,164**
	2014/15 Actual					
5	Common Equity	102,652	40.00%	70,032	10.13%	7,096
6	Long Term Debt	109,746	59.08%	103,431	4.00%	4,140
7	No Cost Capital	1,979	0.92%	1,616	0.00%	0
8	**TOTAL**	**$ 214,377**	**100.00%**	**$ 175,080**	**6.418%**	**$ 11,236**
	2015/16 Actual					
9	Common Equity	105,372	40.00%	70,517	-2.35%	(1,655)
10	Long Term Debt	121,431	59.39%	104,706	3.41%	3,566
11	No Cost Capital	1,384	0.61%	1,069	0.00%	0
12	**TOTAL**	**$ 228,186**	**100.00%**	**$ 176,292**	**1.084%**	**$ 1,911**
	2016/17 Preliminary Actual					
13	Common Equity	110,510	40.00%	77,479	15.40%	11,932
14	Long Term Debt	130,162	59.58%	115,412	3.02%	3,488
15	No Cost Capital	1,007	0.42%	807	0.00%	0
16	**TOTAL**	**$ 241,678**	**100.00%**	**$ 193,698**	**7.960%**	**$ 15,419**
	2017/18 Forecast					
17	Common Equity	120,546	40.00%	90,452	9.00%	8,141
18	Long Term Debt	167,341	59.70%	134,992	2.76%	3,720
19	No Cost Capital	877	0.30%	687	0.00%	0
20	**TOTAL**	**$ 288,764**	***100.00%***	**$ 226,131**	**5.245%**	**$ 11,861**
	2018/19 Forecast					
21	Common Equity	129,029	40.00%	99,709	8.85%	8,824
22	Long Term Debt	203,081	59.76%	148,964	3.37%	5,025
23	No Cost Capital	802	0.24%	600	0.00%	0
24	**TOTAL**	**$ 332,912**	***100.00%***	**$ 249,274**	**5.556%**	**$ 13,849**

Note:
1. Uses deemed capital ratio based on URRC's recommendation (URRC Final Report, paragraph 7, page 34, March 2, 2011).

Schedule 4.5:
Qulliq Energy Corporation 2018/19 General Rate Application
Capitalization – Mid year ($000)

Line No.		2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast
1	COMMON EQUITY						
2	Opening Balance	101,417	99,104	106,200	104,544	116,476	124,617
3	Net Income/Loss before GN Contributions	6,794	7,096	(1,655)	11,932	8,141	8,824
4	(Dividends)/Contributions	0					
5	Closing Balance	108,211	106,200	104,544	116,476	124,617	133,441
6	Mid Year Balance [(L2+L5)/2]	104,814	102,652	105,372	110,510	120,546	129,029
7	DEBT - LONG TERM						
8	Opening Balance	117,493	101,994	117,498	125,364	134,959	199,723
9	Issue	30,000	22,266	15,752	17,823	77,366	24,999
10	Repayment	(8,635)	(6,762)	(7,886)	(8,228)	(12,602)	(18,284)
11	Closing Balance	138,858	117,498	125,364	134,959	199,723	206,438
12	Mid Year Balance [(L8+L11)/2]	128,176	109,746	121,431	130,162	167,341	203,081
13	NO COST CAPITAL						
	GN No-Cost Loan						
14	Opening Balance	1,031	1,031	521	0	0	0
15	Issue	0	0	0	0	0	0
16	Repayment	(510)	(510)	(521)	0	0	0
17	Closing Balance	521	521	0	0	0	0
18	Mid Year Balance [(L14+L17)/2]	776	776	261	0	0	0
	Hearing Reserve and Reserve for Injuries and Damages						
19	Opening Balance	1,276	1,222	1,184	1,062	952	802
20	Additions	0	0	0	0	0	0
21	Use	0	(38)	(123)	(110)	(150)	0
22	Closing Balance	1,276	1,184	1,062	952	802	802
23	Mid Year Balance [(L19+L22)/2]	1,276	1,203	1,123	1,007	877	802
24	No Cost Capital Mid Year Balance [L18+L23]	2,052	1,979	1,384	1,007	877	802
25	TOTAL MID YEAR CAPITALIZATION						
26	[L6+L12+L24]	235,042	214,377	228,186	241,678	288,764	332,912

Schedule 4.6:
Qulliq Energy Corporation 2018/19 General Rate Application
Cost of Long-Term Debt ($000)

Line No.		2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast Effective Interest Rate	2018/19 Forecast Mid-Year Debt Balance	2018/19 Forecast Interest Expense on Mid-year Balance
1	**MID-YEAR DEBT BALANCE (MAD)**	128,176	109,746	121,431	130,162	167,341		203,081	
2	**INTEREST EXPENSE**								
	Interest on Long Term Debt								
	$61m Debenture debt	2,780	2,827	2,629	2,419	2,192	6.81%	27,669	1,884
	$7m Capital loan (Facility B)	123	122	106	90	73	4.24%	1,252	53
	$8m Capital loan (Facility C)	157	185	178	115	93	4.24%	1,605	68
	$8m Capital loan (Facility D)	221	220	190	163	131	4.24%	2,279	97
	$4.8m Capital loan (Facility E)	185	156	135	114	92	4.24%	3,624	154
	$13m Capital loan (Facility F)	401	399	347	297	241	4.24%	4,239	180
	Capital loan (Facility G)	454	221	154	148	145	2.45%	14,167	347
	Capital loan (Facility H)	1,229	85	248	458	600	2.45%	48,701	1,193
	Capital loan (Facility J)	618	178	149	129	150	2.45%	12,400	304
	New loan 2017		0	0	0	700	2.95%	25,472	751
	New loan 2018		0	0	0	196	2.95%	49,174	1,451
	New loan 2019		0	0	0	0	2.95%	12,499	369
	Total Interest Expense	6,167	4,393	4,136	3,933	4,612			6,850
3	**EFFECTIVE COST OF LONG TERM DEBT (L2/L1)**	4.812%	4.003%	3.406%	3.022%	2.756%			3.373%

5.0 VARIANCE FROM REVENUES AT EXISTING RATES

5.1 INTRODUCTION

QEC's 2018/19 revenue requirement (as set out in Chapter 4) results in a variance compared to revenues at existing rates (as set out in Chapter 3).

This section reviews the variance in the test year on a Corporate-wide basis by two components:

- **Variances compared to 2014/15 revenue requirement:** QEC's existing base rates reflect the 2014/15 revenue requirement and load forecast. Changes to test year forecasts for 2018/19 result in small surplus, compared to the 2014/15 revenue requirement.
- **Variances considering existing rate riders:** QEC currently refunds changes in fuel expense relative to 2014/15 GRA prices by way of a fuel rider. The 2018/19 test year revenue requirement incorporates fuel variances into the revenue requirement. When 2018/19 revenue requirements are compared to 2014/15 rates plus the existing fuel rider, it results in a net requirement to increase revenues from customers of approximately 7.6%.

5.2 VARIANCES COMPARED TO 2014/15 REVENUE REQUIREMENT

QEC's revenue requirement and revenues at existing base rates are set out in Table 5.1.

Table 5.1:
Variance from Revenues at Existing Rates 2018/19 ($000s)

	2018/19 Forecast
Non-Fuel O&M	60,173
Production Fuel	48,820
Fixed Asset Amortization	11,205
Return on Rate Base	13,849
Revenue Requirement	134,047
less: Non-Electrical Revenues	2,548
Revenues at Existing Rates	132,363
Surplus/(Shortfall)	864
MW.h sales	178,851
Surplus/(Shortfall) (cents per kW.h)	0.48
Shortfall as % of Existing Revenues	*-0.7%*
Mid-Year Rate Base	249,274

Table 5.1 indicates a surplus from revenues at existing base rates [i.e., excluding impact of the FSR rider] of $0.864 million in 2018/19, incorporating all elements of the revenue requirement described in Chapter 4. As a percentage of existing rate revenues this reflects a shortfall of -0.7% or an average of 0.48 cents/kWh.

Table 5.2 provides a comparison of revenue requirement, revenues and shortfalls between the 2014/15 and 2018/19 test year forecasts. Compared to the 2014/15 GRA forecast, the revenue requirement increased by $3.170 million, however, this is offset by additional revenues from load growth ($5.136 million).

Table 5.2:
Variance from Revenues at Existing Rates
2014/15 GRA Forecast Compared to 2018/19 ($000s)

	2014/15 GRA Forecast	2018/19 Forecast	Changes 2014/15 to 2018/19
Non-Fuel O&M	53,459	60,173	6,715
Production Fuel	56,362	48,820	(7,542)
Fixed Asset Amortization	8,893	11,205	2,312
Return on Rate Base	12,164	13,849	1,685
Revenue Requirement	130,877	134,047	3,170
Less: Non-Electrical Revenues	3,650	2,548	(1,102)
Revenues at Existing Rates	127,227	132,363	5,136
Surplus/(Shortfall)	-	864	864
MW.h sales	172,669	178,851	6,181
Shortfall (cents per kW.h)	0.00	(0.48)	(0.48)
Shortfall as % of Existing Revenues	*0%*	*-0.7%*	

5.3 VARIANCES COMPARED TO EXISTING BASE RATES PLUS RIDERS

QEC filed an application with the Minister for a Fuel Rate Stabilization refund rider of 5.41 cents/kWh effective October 1, 2017 to address ongoing variances between the 2014/15 GRA-approved and actual fuel prices, as well as to recover balances in the FRS fund.

If the current FRS rider remained in place for the 2018/19 test year, the forecast refund to customers would be $9.676 million. With the FRS refund incorporated into the revenue from sales, the shortfall amount for 2018/19 changes from a $0.864 million surplus to a $8.812 million shortfall. This shortfall amount results in required across-the-board rate increases of 7.6% over the existing base energy rates plus FRS rider to recover the full 2018/19 test year revenue requirement.[25]

Table 5.3 illustrates the calculation of the required increase to existing base energy rates plus FSR rider for the 2018/19 test year.

Table 5.3:
Variance from Revenues at Existing Rates and Rider ($000s)

Line No		**2018/19 Forecast**
1	Non-Fuel O&M	60,173
2	Production Fuel	48,820
3	Amortization Expense	11,205
4	Return on Rate Base	13,849
5=Sum(1:4)	Revenue Requirement	134,047
6	Less: Non-Electrical Revenues	2,548
7=5-6	Net Revenue Requirement	131,500
	Rate Revenues	
8	Revenue from Base Energy Rates	125,841
9	Customer charge and Demand Revenue	6,523
10=8+9	Total Existing Rates Revenues	132,363
11=10-7	Surplus/(Shortfall)	864
12	MW.h sales	178,851
13=11/12	Surplus/(Shortfall) (cents per kW.h)	0.48
14=11/8	Shortfall as % of Base Energy Rates	*-0.69%*
15	Existing FSR Rider Revenues/(Refunds)	(9,676)
16=11+15	Surplus/(Shortfall) after FSR Revenues/(Refunds)	(8,812)
17=16/(8+15)	Shortfall as % of Base Energy rate and rider revenues	*7.6%*

[25] The calculation of a required rate increase excludes revenues from customer and demand charges as the Corporation proposes no change to the existing customer and demand charges.

6.0 RATE BASE

6.1 INTRODUCTION

This chapter sets out the calculation of the Corporation's actual Mid-Year Rate Base for the 2014/15, 2015/16 and 2016/17 fiscal years as well as forecasts for 2017/18 and the 2018/19 test year. Specifically this chapter addresses the following topics:

- Gross Plant in Service, including capital additions and disposals;
- Accumulated Amortization (amortization expense is discussed in more detail in Chapter 4); and
- Working Capital.

The Corporation's mid-year ratebase is forecast to be $249.274 million for the 2018/19 test year as shown in Schedule 6.1. The Corporation's mid-year ratebase excludes residual heat related assets and disallowed amounts for the Baker Lake plant.[26]

6.2 RATE APPLICATION ADJUSTMENTS TO AUDITED FINANCIAL STATEMENTS

The adoption of public sector accounting (PSA) standards resulted in several changes to the calculation of rate base. This section reviews the impacts of these changes.

[26] Disallowed amount of $1.745 million from plant in service per the URRC directive from the Final Report on QEC's 2004/05 GRA.

6.2.1 CUSTOMER CONTRIBUTIONS

Under PSA standards, revenue received from customers for the purpose of purchasing tangible capital assets are recognized as revenue when the related assets are acquired. However, for ratemaking purposes, the Corporation wanted to ensure that customers continued to see the benefits of customer contribution revenues in the calculation of ratebase. Therefore, for GRA purposes, the Corporation treats customer contributions as an offset to ratebase, consistent with the treatment as deferred revenue in rate applications prior to adopting the PSA standards. The net result of this treatment is a reduction to revenue requirement (including both amortization expense and return on ratebase) of about $1.600 million. This treatment ensures customers continue to see benefits for ratemaking purposes similar to the methods used in previous applications.

6.2.2 GOVERNMENT TRANSFERS

The Corporation has adopted the revised version of PS 3410 - Government Transfers. The impact of adopting this standard was to reclassify government funding for capital projects received in prior years from a deferred capital funding liability to accumulated surplus.

Similar to the treatment of customer contributions, the Corporation wanted to ensure customers still realized the benefits of this funding for rate making purposes. Therefore in this rate application, QEC has continued to treat these government transfers as deferred capital funding. The net result of this treatment is a reduction to revenue requirement (including both amortization expense and return on ratebase) of about $0.650 million.

6.3 GROSS PLANT IN SERVICE

Gross plant in service represents the accounting cost of all QEC assets in service related to the provision of electricity service. Each year the gross plant in service calculation considers the opening balance, plus capital additions, less disposals or other adjustments to arrive at the ending balance. The mid-year gross plant figures are the simple average of the opening gross plant balance and the ending gross plant balance. Gross plant in service calculations for 2014/15 through 2018/19 are set out in Schedule 6.2. Actual and forecast capital additions, as well as descriptions of capital additions greater than $400,000 are set out in Appendix B.

Table 6.1 summarizes the changes to the gross plant in service from the 2014/15 GRA forecast to the 2018/19 test year forecast.

Table 6.1:
Gross Plant in Service ($000)

Gross Plant by Function	2014/15 GRA	2018/19 Forecast	Increase
Diesel Plant	217,080	312,985	95,906
Distribution Plant	40,692	46,423	5,730
General Plant	27,923	34,415	6,492
Energy Utilization Group	1,425	176	-1,250
Less: Insurance Proceeds	-2,956	-22,714	-19,758
Total	**284,165**	**371,285**	**87,120**

Forecast 2018/19 gross plant in service increased by approximately $87.120 million compared to the 2014/15 GRA forecast. The majority of the increase in gross plant in service is driven by additions to diesel plant ($95.906 million). Major diesel plant additions include the Iqaluit main plant expansion upgrades ($40.440 million in 2013/14 and $0.633 million in 2014/15), the Taloyoak power plant ($15.914 million), the Qikiqtarjuaq power plant ($16.159 million), and the Pangnirtung power plant replacement ($19.022 million).

Distribution plant increased by $5.730 million (or 7% of the total increase), offset by customer contributions. The additions to general plant mainly reflect the Nunavut supervisory control and data acquisition (SCADA) upgrade (total of $1.126 million) in 2016/17. The reduction in Energy Utilization Group reflect disposal of wind turbines due to issues with operation.

Detailed discussion of the actual and forecast capital additions is provided in Appendix B.

6.4 ACCUMULATED AMORTIZATION

Accumulated Amortization represents the collected amortization for QEC's assets in service related to the provision of electricity service. For each year from 2014/15 through 2018/19 the Accumulated Amortization calculation considers the opening balance, plus amortization expense, less disposals and other adjustments to arrive at the ending balance. Schedule 6.3 sets out the calculation of the Mid-Year Accumulated Amortization.

A comparison of 2014/15 GRA forecast accumulated amortization to the 2018/19 test year forecast is provided in Table 6.2.

Table 6.2:
Accumulated Amortization ($000)

Accumulated Amortization by Function	2014/15 GRA	2018/19 Forecast	Increase
Diesel Plant	85,140	117,208	32,068
Distribution Plant	10,809	13,280	2,471
General Plant	9,984	14,453	4,469
Energy Utilization Group	1,239	198	-1,041
Less: Insurance Proceeds	-1,342	-3,573	-2,230
Total	**105,830**	**141,566**	**35,736**

2018/19 forecast accumulated amortization has increased by $35.736 million compared to the 2014/15 GRA forecast. The change reflects continued amortization of the Corporation's assets offset by disposals. Reduction in the distribution plant accumulated amortization reflects removal of assets funded by customer contributions.

6.5 WORKING CAPITAL

Cash working capital has been calculated based on the results of a lead-lag study provided in the 2010/11 GRA (Appendix D of 2010/11 Phase I GRA), which returned a result of 14.63 net lag days. The net lag days figure is multiplied by average daily expenses and added to the impact of GST lag to calculate a cash working capital provision for each year.

Other components of working capital are supplies inventory, fuel inventory and pre-payments of rent and insurance. Schedule 6.4 shows the calculation of the working capital provision for 2014/15 through 2018/19. Schedules 6.5 through 6.9 set out the calculation of cash working capital for each year.

The supplies inventory component of working capital also includes the balances of significant spare parts, which previously were capitalized.

Schedule 6.1:
Qulliq Energy Corporation 2018/19 General Rate Application
Rate Base ($000)

Line No.		2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast
1	**Gross Plant in Service**						
2	Beginning of Year	255,899	242,806	251,808	259,467	304,508	345,193
3	Add: Additions and Adjustments	28,266	9,314	14,266	46,081	40,684	26,092
4	Less: Disposals and Transfers	0	(313)	(6,607)	(1,040)	-	-
5	End of Year	284,165	251,808	259,467	304,508	345,193	371,285
6	Mid Year Balance =(L2+L5)/2	270,032	247,307	255,638	281,988	324,850	358,239
7	**Accumulated Amortization**						
8	Beginning of Year	97,186	96,016	104,392	110,512	121,704	131,017
9	Add: Amortization Expense	8,644	9,365	10,788	11,703	9,313	10,549
10	Less: Disposals and Transfers	0	(256)	(4,667)	(511)	-	-
11	End of Year	105,830	105,125	110,512	121,704	131,017	141,566
12	Mid Year Balance = (L8+L11)/2	101,508	100,570	107,452	116,108	126,360	136,291
13	**Mid Year Net Plant in Service (L6 - L12)**	168,524	146,737	148,186	165,880	198,490	221,947
14	**Add: Mid-Year Working Capital**	20,205	28,343	28,106	27,818	27,641	27,326
15	**Mid Year Rate Base**	**188,729**	**175,080**	**176,292**	**193,698**	**226,131**	**249,274**

Notes
1. Gross Plant in Service and Accumulated amortization are net of Residual Heat.
2. Gross Plant in Service and Accumulated amortization reflect exclusion of the disallowed amount of $1.745 million from utility plant in service per the URRC directive from the Final Report on QEC's 2004/05 GRA.
3. Under PSA Standards Government and customer deferred capital funding for the purpose of purchases of tangible capital assets are recognized as revenue when the related assets are acquired. Based on this, the adjustment was made to the annual reports to de-recognize the customer deferred capital funding liability, with an offsetting adjustment to accumulated surplus in the year of transition.

Schedule 6.2:
Qulliq Energy Corporation 2018/19 General Rate Application
Gross Plant in Service ($000)

Line No.	Gross Plant by Major FERC Category	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast
	Diesel Plant						
1	Beginning of Year	193,556	185,572	192,162	196,491	238,053	288,369
2	Add: Additions	23,524	6,591	9,647	42,211	50,316	24,616
3	Add/Less: Adjustments		-	-			
4	Less: Disposals		-	(5,318)	(649)		
5	End of Year	217,080	192,162	196,491	238,053	288,369	312,985
6	**Mid-Year Diesel Plant**	205,318	188,867	194,327	217,272	263,211	300,677
	Distribution Plant						
7	Beginning of Year	36,867	33,369	34,660	38,002	40,466	45,900
8	Add: Additions	3,825	1,291	3,342	2,465	5,433	523
9	Add/Less: Adjustments		-	-			
10	Less: Disposals		-	-	-		
11	End of Year	40,692	34,660	38,002	40,466	45,900	46,423
12	**Mid-Year Distribution Plant**	38,780	34,014	36,331	39,234	43,183	46,161
	General Plant						
13	Beginning of Year	27,006	25,373	26,493	27,484	28,770	33,462
14	Add: Additions	917	1,433	1,277	1,405	4,692	953
15	Add/Less: Adjustments		-	-			
16	Less: Disposals		(313)	(286)	(120)		
17	End of Year	27,923	26,493	27,484	28,770	33,462	34,415
18	**Mid-Year General Plant**	27,465	25,933	26,989	28,127	31,116	33,939
	Energy Utilization Group						
19	Beginning of Year	1,425	1,450	1,450	447	176	176
20	Add: Additions	-	-	-	-	-	-
21	Add/Less: Adjustments		-	-			
22	Less: Disposals		-	(1,003)	(271)		
23	End of Year	1,425	1,450	447	176	176	176
24	**Mid-Year Energy Utilization Group**	1,425	1,450	948	311	176	176
	Insurance Proceeds						
25	Beginning of Year	(2,956)	(2,956)	(2,956)	(2,956)	(2,956)	(22,714)
26	Add: Additions		-	-	-	(19,758)	-
27	Add/Less: Adjustments		-	-	-	-	-
28	Less: Disposals		-	-	-	-	-
29	End of Year	(2,956)	(2,956)	(2,956)	(2,956)	(22,714)	(22,714)
30	**Mid-Year Insurance Proceeds**	(2,956)	(2,956)	(2,956)	(2,956)	(12,835)	(22,714)
31	**Total Beginning of Year Gross Plant in Service**	**255,899**	**242,806**	**251,808**	**259,467**	**304,508**	**345,193**
32	**Total End of Year Gross Plant in Service**	**284,165**	**251,808**	**259,467**	**304,508**	**345,193**	**371,285**
33	**Total Mid-Year Gross Plant in Service**	**270,032**	**247,307**	**255,638**	**281,988**	**324,850**	**358,239**

Notes
1. Gross Plant in Service is net of Residual Heat.
2. Gross Plant in Service reflects exclusion of the disallowed amount of $1.745 million from utility plant in service per the URRC directive from the Final Report on QEC's 2004/05 GRA.
3. Generation and Distribution Gross Plant in Service reflect exclusion of the amount for Government of Nunavut and customer contributions.

Schedule 6.3:
Qulliq Energy Corporation 2018/19 General Rate Application
Accumulated Amortization ($000)

Line No.	Accumulated Amortization by Major FERC Category	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast
1	**Diesel Plant**						
2	Beginning of Year	78,221	77,942	85,641	91,042	100,409	108,271
3	Add: Amortization	6,919	7,699	8,864	9,751	7,862	8,936
4	Less: Disposals and Adjustments	-	-	(3,463)	(384)		
5	End of Year	85,140	85,641	91,042	100,409	108,271	117,208
	Mid-Year Diesel Plant	81,680	81,791	88,341	95,725	104,340	112,740
6	**Distribution Plant**						
7	Beginning of Year	10,206	8,775	9,565	10,448	11,338	12,278
8	Add: Amortization	603	790	883	890	940	1,002
9	Less: Disposals and Adjustments	-	-	-	-		
10	End of Year	10,809	9,565	10,448	11,338	12,278	13,280
	Mid-Year Distribution Plant	10,508	9,170	10,006	10,893	11,808	12,779
11	**General Plant**						
12	Beginning of Year	8,812	9,371	10,064	10,970	12,002	13,178
13	Add: Amortization	1,172	949	1,107	1,133	1,176	1,275
14	Less: Disposals and Adjustments	-	(256)	(201)	(101)		
15	End of Year	9,984	10,064	10,970	12,002	13,178	14,453
	Mid-Year General Plant	9,398	9,717	10,517	11,486	12,590	13,816
16	**Energy Utilization Group**						
17	Beginning of Year	1,211	1,193	1,197	205	186	192
18	Add: Amortization	28	4	11	7	6	6
19	Less: Disposals and Adjustments	-	-	(1,003)	(26)		
20	End of Year	1,239	1,197	205	186	192	198
	Mid-Year Energy Utilization Group	1,225	1,195	701	196	189	195
21	**Insurance Proceeds**						
22	Beginning of Year	(1,265)	(1,265)	(2,075)	(2,153)	(2,231)	(2,902)
23	Add: Amortization	(78)	(78)	(78)	(78)	(671)	(671)
24	Less: Disposals and Adjustments	-	(733)	-	-		
25	End of Year	(1,342)	(2,075)	(2,153)	(2,231)	(2,902)	(3,573)
	Mid-Year Insurance Proceeds	(1,304)	(1,670)	(2,114)	(2,192)	(2,567)	(3,237)
26	**Total Beginning of Year Accumulated Amortization**	**97,186**	**96,016**	**104,392**	**110,512**	**121,704**	**131,017**
27	**Total End of Year Accumulated Amortization**	**105,830**	**104,392**	**110,512**	**121,704**	**131,017**	**141,566**
28	**Total Mid-Year Accumulated Amortization**	**101,508**	**100,204**	**107,452**	**116,108**	**126,360**	**136,291**

Notes
1. Accumulated amortization is net of Residual Heat.
2. Accumulated amortization reflects exclusion of amortization expenses of the disallowed amount of $1.745 million from utility plant in service per the URRC directive from the Final Report on QEC's 2004/05 GRA.
3. Generation and Distribution Plant Accumulated Amortization reflects exclusion of the amount for Government of Nunavut and customer contributions.

Schedule 6.4:
Qulliq Energy Corporation 2018/19 General Rate Application
Working Capital Requirement ($000)

Line No.		2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast
1	**Cash Working Capital**	**4,403**	**4,386**	**4,433**	**4,349**	**4,195**	**4,287**
2	**Less: Mid-Year Customer Deposits**	**-878**	**-1,140**	**-1,317**	**-1,386**	**-1,405**	**-1,423**
3	**Add: Supplies Inventory**						
4	Beginning of Year (note 1)	5,819	11,793	13,643	14,438	15,202	14,428
5	End of Year	5,819	13,643	14,438	15,202	14,428	14,428
6	**Mid-Year Balance**	**5,819**	**12,718**	**14,040**	**14,820**	**14,815**	**14,428**
7	**Fuel Average Monthly Balance**	**9,672**	**10,806**	**9,188**	**8,018**	**8,018**	**8,018**
8	**Mid-Year Rent Prepayment**	**782**	**906**	**992**	**1,169**	**1,169**	**1,169**
9	**Mid-Year Insurance Prepayment**	**408**	**667**	**770**	**849**	**849**	**849**
10	**Total Mid-Year Working Capital Requirement**	**20,205**	**28,343**	**28,106**	**27,818**	**27,641**	**27,326**

Note:
1. Actual and forecast years include spare parts, supplies and lubricants and other inventory. The significant spare parts, previously capitalized, were reclassified as “inventory for use” to comply with PSA Standards.

Schedule 6.5:
Qulliq Energy Corporation 2018/19 General Rate Application
2014/15 Actual Cash Working Capital ($000)

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	29,611	81	14.63	1,187
2	Fuel and Lubricants	56,077	154	14.63	2,248
3	Supplies and Services	16,472	45	14.63	660
4	Travel and Accomodation	4,732	13	14.63	190
5	**Total Expenses**	**106,893**	**293**		**4,285**
6	GST Expenditure Lag	3,864	11	14.87	157
7	GST Remittance Lag	6,289	17	(3.30)	-57
8	**Total GST**				**101**
9	**Total Cash Working Capital**				**4,386**

Schedule 6.6:
Qulliq Energy Corporation 2018/19 General Rate Application
2015/16 Actual Cash Working Group ($000)

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	30,386	83	14.63	1,218
2	Fuel and Lubricants	55,318	152	14.63	2,217
3	Supplies and Services	18,003	49	14.63	722
4	Travel and Accomodation	4,391	12	14.63	176
5	**Total Expenses**	**108,098**	**296**		**4,333**
6	GST Expenditure Lag	3,886	11	14.87	158
7	GST Remittance Lag	6,464	18	(3.30)	-58
8	**Total GST**				**100**
9	**Total Cash Working Capital**				**4,433**

Schedule 6.7:
Qulliq Energy Corporation 2018/19 General Rate Application
2016/17 Actual Cash Working Capital ($000)

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	33,273	91	14.63	1,334
2	Fuel and Lubricants	47,575	130	14.63	1,907
3	Supplies and Services	20,705	57	14.63	830
4	Travel and Accomodation	4,708	13	14.63	189
5	**Total Expenses**	**106,261**	**291**		**4,260**
6	GST Expenditure Lag	3,649	10	14.87	149
7	GST Remittance Lag	6,516	18	(3.30)	-59
8	**Total GST**				**90**
9	**Total Cash Working Capital**				**4,349**

Schedule 6.8:
Qulliq Energy Corporation 2018/19 General Rate Application
2017/18 Forecast Cash Working Capital ($000)

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	30,376	83	14.63	1,214
2	Fuel and Lubricants	48,051	131	14.63	1,921
3	Supplies and Services	19,124	52	14.63	765
4	Travel and Accomodation	5,213	14	14.63	208
5	**Total Expenses**	**102,764**	**281**		**4,108**
6	GST Expenditure Lag	3,619	10	14.87	147
7	GST Remittance Lag	6,677	18	(3.30)	-60
8	**Total GST**				**87**
9	**Total Cash Working Capital**				**4,195**

Schedule 6.9:
Qulliq Energy Corporation 2018/19 General Rate Application
2018/19 Forecast Cash Working Capital ($000)

Line No.		Year End Balance	Daily Expense	Net Lag Days	Cash Working Capital
1	Salaries and Wages	31,287	85	14.63	1,251
2	Fuel and Lubricants	48,820	133	14.63	1,952
3	Supplies and Services	19,584	54	14.63	783
4	Travel and Accomodation	5,317	15	14.63	213
5	**Total Expenses**	**105,008**	**287**		**4,198**
6	GST Expenditure Lag	3,686	10	14.87	150
7	GST Remittance Lag	6,746	18	(3.30)	-61
8	**Total GST**				**89**
9	**Total Cash Working Capital**				**4,287**

7.0 COST OF SERVICE STUDY AND RESULTS

7.1 INTRODUCTION

This chapter presents the Corporation's cost-of-service study ("COS study") results for the 2018/19 test year. A COS study is commonly used as an analytical tool in the ratemaking process. A COS study can provide useful information such as unit costs to serve different customers (such as $/kWh, $/customer month) and revenue to cost coverage ratios. However, it must be recognized that any COS study involves estimation and a degree of professional judgement and therefore the results cannot be considered exact.

The purpose of a COS study is to fairly allocate a utility's revenue requirement among the different customer classes. While there are many potential allocation methods, the core objective is to allocate costs to the customer classes consistent with principles of cost causation based on customer characteristics such as energy consumption and peak demand.

There is no absolute right or wrong allocation method, as each utility's operating circumstances and cost drivers are different. The objective for the utility is to select methods which best represent cost causation and the equitable sharing of costs among customers in a manner appropriate for the unique circumstances of the utility.

To provide services to its customers, the Corporation must receive sufficient revenues to recover its costs. Adequate cost recovery is a necessary condition for maintaining reliable service by the Corporation. The COS study methods used in this Application apply cost-of-service concepts to embedded accounting costs in order to calculate the fair share of the Corporation's total revenue requirement for each customer class.

The last COS study review by the URRC was conducted as part of QEC's 2010/11 GRA. URRC Report 2012-01 to the Minister recommended accepting QEC's proposal to adopt a Nunavut wide COS approach.[27]

The Corporation filed its last COS study for Nunavut communities as part of its 2014/15 GRA. However, the Phase II component of the 2014/15 GRA was retracted in accordance with the January 29, 2014 Instruction, and as such was not reviewed by the URRC. The Minister's Instruction from January 29, 2014 directed QEC to file a Phase II General Rate Application that provides several COS study options for consideration in its next GRA. In accordance with this Instruction, the Corporation conducted COS studies for the following scenarios:

- Community based COS study;
- Capital zone based COS study; and
- Territory-wide COS study.

COS studies for the same scenarios were also conducted in the 2010/11 Phase II GRA, where the merits of each scenario were assessed and considered for different criteria, including cost causation, cost stability over time, consistency with territorial government policy, consistency with other utility practices, and administrative efficiency. The

[27] Report 2012-01 from January 27, 2012 on QEC's 2010/11 Phase II GRA.

Corporation reviewed the COS study scenarios in preparation of the current Application, and arrived at the same conclusions. Based on these considerations, the Corporation is recommending a territory-wide COS study approach. A comparison of the territory-wide COS study to community-based COS and capital-zone COS studies is provided in Section 7.3.

The Corporation's 2018/19 COS study is provided in Appendix C. All methods used in the current COS study are consistent with the previous URRC reviews and also reflect the policy considerations identified in the January 29, 2014 Instruction.

The results of the COS study are used as inputs in developing the rate proposals for the Application.

7.2 CLASS REVENUE TO COST COVERAGE RATIOS AND UNIT COSTS

Results of the Corporation's 2018/19 COS study are presented in Table 7.1. Detailed COS study schedules for the territory-wide COS study are provided in Appendix D.

The following information is provided for each customer class:

- 2018/19 forecast revenue at equal percentage across-the-board rate increase;
- 2018/19 COS study class revenue requirements;
- Revenue cost coverage (RCC) ratio;
- Average COS unit costs for:
    - Demand ($/kW);

- o Energy ($/kWh); and
- o Customer ($/month).

Table 7.1:
2018/19 Cost of Service Results and Average Unit Costs

Customer Class	Revenue at Equal Percentage Across-the-Board Rate Increases	COS Customer Class Revenue Requirement	Revenue Cost Coverage Ratio	COS Demand Charge	COS Customer Charge	COS Energy Charge
	$000	$000		$/kW	$/Cust./Month	cents/kWh
Domestic	53,838	55,515	97.0%		34.96	74.61
Commercial	75,925	73,909	102.7%	68.15	61.08	34.50
Streetlighting	1,737	2,075	83.7%		34.96	105.38
Total	131,500	131,500				

The results indicate that, if rate increases were applied on an equal-percentage-across-the-board basis, the domestic rate class RCC ratio would be slightly below 100%, while the commercial rate class RCC ratio would be somewhat above 100% - however both rate classes would have an RCC ratio within the 95% to 105% zone of reasonableness.

Streetlighting customer class would have an RCC ratio of 83.7%, suggesting that this class should receive higher than average rate increases.

The results also indicate that the existing demand and customer charges ($8/kW for commercial customers and $18/month for residential customers, respectively) are low compared to the COS study outputs.

Maintaining the existing demand and customer charges in the COS study results in higher average energy unit costs as shown in Table 7.2.

Table 7.2:
Cost of Service Results and Average Energy Unit Costs under Existing Demand and Customer Charges

Customer Class	Revenue at Equal Percentage Across-the-Board Rate Increases	COS Customer Class Revenue Requirement	Revenue Cost Coverage Ratio	COS Result with Existing Customer/Demand Charge		
				Existing Demand Charge	Existing Customer Charge	COS Energy Charge
	$000	$000		$/kW	$/Cust./Month	cents/kWh
Domestic	53,838	55,515	97.0%		18.00	78.16
Commercial	75,925	73,909	102.7%	8.00		64.08
Streetlighting	1,737	2,075	83.7%			106.48
Total	131,500	131,500				

Maintaining demand and customer charges at the existing level results in 3.55 cents/kWh higher energy rates for the domestic rate class, 29.58 cents/kWh higher energy rates for the commercial rate class, and 1.10 cents/kWh higher energy rates for the streetlighting rate class.

7.3 ALTERNATIVE COST OF SERVICE STUDIES

The Ministerial Instruction dated January 29, 2014 directed QEC to file a Phase II GRA that provides several cost-of-service study options for consideration at the time of its 2018 GRA. QEC is recommending that the Minister approve a single territory-wide COS approach. However, the Corporation also completed COS analyses based on two alternative COS approaches:

1. Separate COS studies for each community.

2. A COS study that groups all communities into a single territory-wide capital zone.[28]

Table 7.3 compares the class revenue requirement results by community for each of the three cost of service approaches.

[28] A capital-zone based COS study involves averaging capital related costs across all the communities in a particular zone, while maintaining a community based approach to non-capital operating and maintenance costs. The rationale for grouping all communities into a single territory-wide capital zone was discussed in the 2010/11 Phase II GRA Section 6.3.

Table 7.3:
2018/19 Revenue Requirement Comparison by Rate Class and Community

Plant No.		Domestic Revenue Requirement			Commercial Revenue Requirement			Streetlighting Revenue Requirement			*Total Revenue Requirement*		
		Territory-Wide COS ($000)	Community Based COS ($000)	Capital-zone Based COS ($000)	Territory-Wide COS ($000)	Community Based COS ($000)	Capital-zone Based COS ($000)	Territory-Wide COS ($000)	Community Based COS ($000)	Capital-zone Based COS ($000)	Territory-Wide COS ($000)	Community Based COS ($000)	Capital-zone Based COS ($000)
501	Cambridge Bay	3,005	2,894	3,002	5,771	5,436	5,759	131	217	135	*8,907*	*8,547*	*8,896*
502	Gjoa Haven	1,897	2,012	2,053	2,112	2,222	2,319	81	84	87	*4,090*	*4,318*	*4,459*
503	Taloyoak	1,401	2,080	1,623	1,322	1,918	1,557	60	70	68	*2,783*	*4,068*	*3,247*
504	Kugaaruk	1,204	1,365	1,402	844	956	1,008	33	31	42	*2,081*	*2,351*	*2,452*
505	Kugluktuk	2,111	1,965	2,284	1,991	1,947	2,177	70	215	78	*4,172*	*4,127*	*4,539*
601	Rankin Inlet	4,558	3,667	4,183	7,597	6,314	6,957	152	336	145	*12,306*	*10,317*	*11,285*
602	Baker Lake	3,130	3,041	3,086	3,048	2,851	3,042	118	85	114	*6,296*	*5,977*	*6,242*
603	Arviat	3,184	3,073	3,126	3,307	3,241	3,266	101	112	101	*6,592*	*6,425*	*6,493*
604	Coral Harbour	1,227	1,364	1,424	1,265	1,411	1,490	54	56	61	*2,547*	*2,831*	*2,975*
605	Chesterfield Inlet	594	688	723	809	942	993	28	24	34	*1,431*	*1,654*	*1,751*
606	Whale Cove	624	910	797	678	916	874	36	36	44	*1,337*	*1,862*	*1,715*
607	Naujaat	1,354	1,549	1,376	1,657	1,886	1,695	33	58	38	*3,044*	*3,493*	*3,109*
701	Iqaluit	15,356	13,214	13,556	25,422	22,599	22,216	446	432	423	*41,224*	*36,245*	*36,195*
702	Pangnirtung	2,095	2,012	2,127	2,269	2,165	2,318	150	104	137	*4,515*	*4,281*	*4,582*
703	Cape Dorset	1,849	1,794	1,996	2,018	1,954	2,209	81	56	84	*3,947*	*3,804*	*4,289*
704	Resolute Bay	480	632	550	2,230	2,462	2,524	42	38	50	*2,753*	*3,131*	*3,124*
705	Pond Inlet	2,165	2,161	2,139	2,283	2,309	2,282	121	93	111	*4,569*	*4,562*	*4,532*
706	Igloolik	2,256	2,048	2,183	2,491	2,301	2,427	101	72	96	*4,848*	*4,422*	*4,706*
707	Hall Beach	1,146	1,398	1,307	1,222	1,353	1,399	44	41	51	*2,412*	*2,792*	*2,757*
708	Qikiqtarjuaq	859	1,551	999	1,056	1,806	1,240	34	47	41	*1,950*	*3,404*	*2,280*
709	Kimmirut	608	865	761	715	1,008	906	35	38	42	*1,359*	*1,910*	*1,709*
710	Arctic Bay	1,250	1,290	1,359	970	1,018	1,076	36	27	41	*2,256*	*2,335*	*2,476*
711	Clyde River	1,516	2,090	1,970	1,102	1,534	1,465	27	30	39	*2,645*	*3,653*	*3,474*
712	Grise Fiord	260	756	434	466	1,254	778	25	54	39	*751*	*2,065*	*1,251*
713	Sanikiluaq	1,387	1,556	1,517	1,263	1,339	1,403	35	29	43	*2,685*	*2,925*	*2,963*
	Totals	55,515	55,973	55,977	73,909	73,144	73,382	2,075	2,382	2,140	*131,500*	*131,500*	*131,500*

A review of Table 7.3 shows that, in general, communities with smaller customer bases are allocated higher revenue requirement under the community based COS study, whereas communities with bigger customer bases are allocated relatively smaller revenue requirement. In particular:

- Grise Fiord, which is the community with the smallest customer base, is allocated a revenue requirement of $0.260 million to the domestic rate class under the territory-wide COS study, which increases to $0.434 million under capital-zone based COS study, and to $0.756 million under the community-based COS study. Revenue requirement allocated to the commercial rate class in this community is $0.466 million under territory-wide COS study, which increases to $0.778 million under capital-zone based COS study, and to $1.254 million under community-based COS study.

  Whale Cove, the second smallest community, is allocated a revenue requirement of $0.624 million to the domestic rate class under the territory-wide COS study, which increases to $0.797 million under the capital-zone based COS study, and to $0.910 million under the community-based COS study. Revenue requirement allocated to commercial rate class in this community is $0.678 million under territory-wide COS study, which increases to $0.874 million under capital-zone based COS study, and to $0.916 million under the community-based COS study.

- Rankin Inlet's allocated revenue requirement, the second biggest community in terms of the customer base, increases from $3.667 million under the community-based COS study to $4.183 million under the capital-zone based COS study and to $4.558 million under the territory-wide COS study for the domestic rate class. The revenue requirement allocated to the commercial rate class in Rankin Inlet increases from $6.314 million under the community-based COS study to $6.957 million under the capital-zone based COS study and to $7.597 million under the territory-wide COS study.

Similarly, Igloolik's allocated revenue requirement, which has one of the biggest percentage variations, increases from $2.048 million under the community-based COS study to $2.183 million under the capital-zone based COS study and to $2.256 million under the territory-wide COS study for the domestic rate class. The revenue requirement allocated to the commercial rate class in Igloolik increases from $2.301 million under the community-based COS study to $2.427 million under the capital-zone based COS study and to $2.491 million under territory-wide COS study.

- It important to note that the territory-wide COS study would allocate 10% or higher revenue requirement to only three communities relative to the community-based COS study (Rankin Inlet, Iqaluit and Igloolik), whereas 12 communities will see a revenue requirement decrease of 10% or higher relative to the community-based COS study.

Based on the review of the alternatives, the Corporation is recommending the Minister approve the single territory-wide COS approach for the following reasons:

- **Cost stability over time:** the territory-wide cost-of-service study provides the best cost stability over time by averaging the costs of major capital projects and major operations and maintenance costs over the entire territory.

- **Consistency with Canadian Utility Practice:** the Corporation is not aware of another utility in Canada that calculates separate COS studies for each community in its service area.

- **Administrative Efficiency:** the territory-wide approach does not require a method for separating head office costs between communities or regions. This reduces the complexity of the study.

- **Consistency with Territorial Policy:** the territory-wide approach is consistent with the guiding principles set out in the GN's 2014-2018 planning document Sivumu Abluqta: Stepping Forward Together.[29] In particular, the following core values are consistent with a territory-wide COS study approach:

    - Inuuqatigiitsiarniq (respecting others, relationships and caring for people);
    - Pijitsirniq (serving and providing for family and/or community); and
    - Piliriqatigiinniq/Ikajuqtigiinniq (working together for a common cause).

[29] Available: http://www.gov.nu.ca/information/sivumut-abluqta. Accessed July 19, 2017.

8.0 RATE DESIGN

8.1 INTRODUCTION

This chapter reviews the Corporation's proposed rates and rate structures to be implemented effective April 1, 2018 and April 1, 2019.

Section 8.2 reviews the Corporation's recommended approach with respect to the rate structure in Nunavut consistent with the recommended single territory-wide COS approach.

Section 8.3 of this chapter reviews the rate design criteria and objectives of the Corporation for this application.

Section 8.4 summarises the Corporation's proposal for rates effective April 1, 2018 and April 1, 2019.

8.2 NUNAVUT RATE STRUCTURE REVIEW

Section 7.3 of this application compares different COS study options and recommends that the Minister approve a single territory-wide COS approach. In support of this recommendation QEC provides several reasons, which include cost stability, consistency with Canadian utility practice, administrative efficiency, and consistency with Territorial policy objectives. All of these considerations are equally applicable to the Corporation's proposed rate design. The Corporation is proposing to transition the current community based rate structure to a single territory-wide rate structure over approximately the next six years. This application addresses the first two years of the proposed transition to territory-wide rates. The remaining four years of transition would be the subject of a future application. The Corporation is proposing to transition to territory-wide rates for a number of reasons including:

- The current differential rates by community do not accurately reflect community based costs. If the intent of community based rates is to reflect different costs of service in each community, then the current community-based rates do not accomplish this objective.
- The rate adjustments required to achieve community-based rates that are fully reflective of community-based costs would be substantial. Far greater than what is proposed in this application.
- The recent practice of increasing rates by equal percentages for all rate classes results in proportionately higher rate increases for communities with higher starting points. This means that the gap (in dollars) between the lowest cost communities and the highest cost communities gets wider every time rate increases are applied on an equal percentage basis to all customer classes.
- Large capital projects put enormous upward pressure on rates, particularly for smaller communities. In some cases communities would face rate increases in excess of 50% in order to pay for required capital projects.
- As QEC begins to roll out alternative energy projects, under community-based rates only the community where the alternative energy project is located takes on the risks (such as higher initial capital costs) and benefits (lower fuel expense) of the project. Further, if there are territorial or federal government contributions to

alternative energy projects, the benefit of the government funding accrues only to the individual community where the project is located.

Further discussion on each of these topics is provided in the following section.

8.2.1 COMPARISON OF EXISTING RATES TO COMMUNITY BASED COS RATES

The last substantial rate rebalancing for Nunavut communities was implemented as part of NTPC's 1995/98 GRA, nearly 20 years ago. That application was prepared on the basis of a "community-based" approach to rate design.

Rate adjustments since QEC's establishment have typically been implemented on an equal percentage basis across all rate classes.[30] As a result, for the last 20 years, the changes to community energy rates were not linked to the cost of service in those communities. Figures 8.1 through 8.4 compare the existing energy rates (including the existing fuel refund rider) to the community-based COS rates.

As illustrated in the figures, existing rates do not reflect the community-based COS rates in many communities:

- Domestic non-government rates differ from COS rates by more than 10% in 16 communities. In Grise Fiord, existing rates would need to increase by 172% to achieve rates consistent with the community's cost of service.

[30] The only exception when rate adjustments were implemented on a cents/kWh basis was on November 1, 2005 to implement capital stabilization-rebalancing levy rate riders. In that adjustment most communities received the same rate adjustment. A small number of communities received differential adjustments.

- Domestic government rates differ from COS rates by more than 10% in 17 communities. In Grise Fiord, existing rates would need to increase by 123% to achieve rates consistent with the community's cost of service.

- Commercial non-government rates differ from COS rates by more than 10% in 16 communities. In Grise Fiord, existing rates would need to increase by 80% to achieve rates consistent with the community's cost of service.

- Commercial government rates differ from COS rates by more than 10% in 15 communities. In Grise Fiord, existing rates would need to increase by 80% to achieve rates consistent with the community's cost of service.

Figure 8.1:
Existing Rates Comparison to COS - Domestic Non-Government

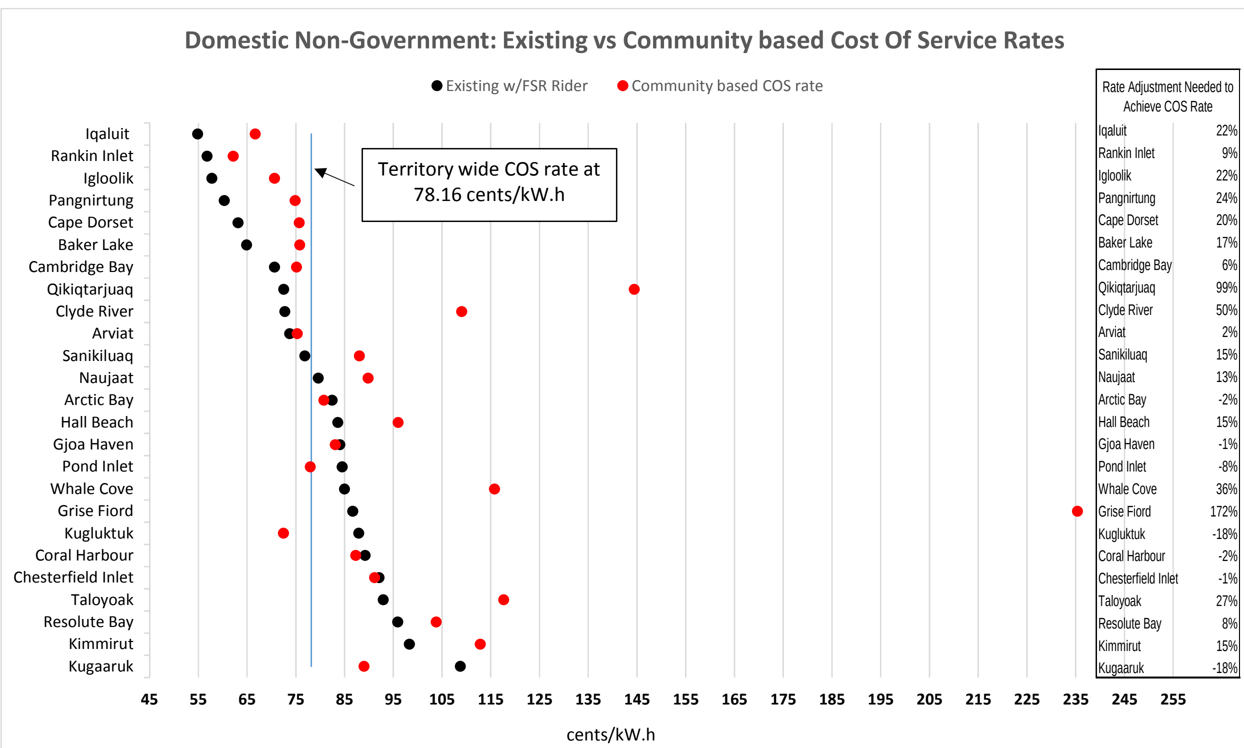


Figure 8.2:
Existing Rates Comparison to COS - Domestic Government

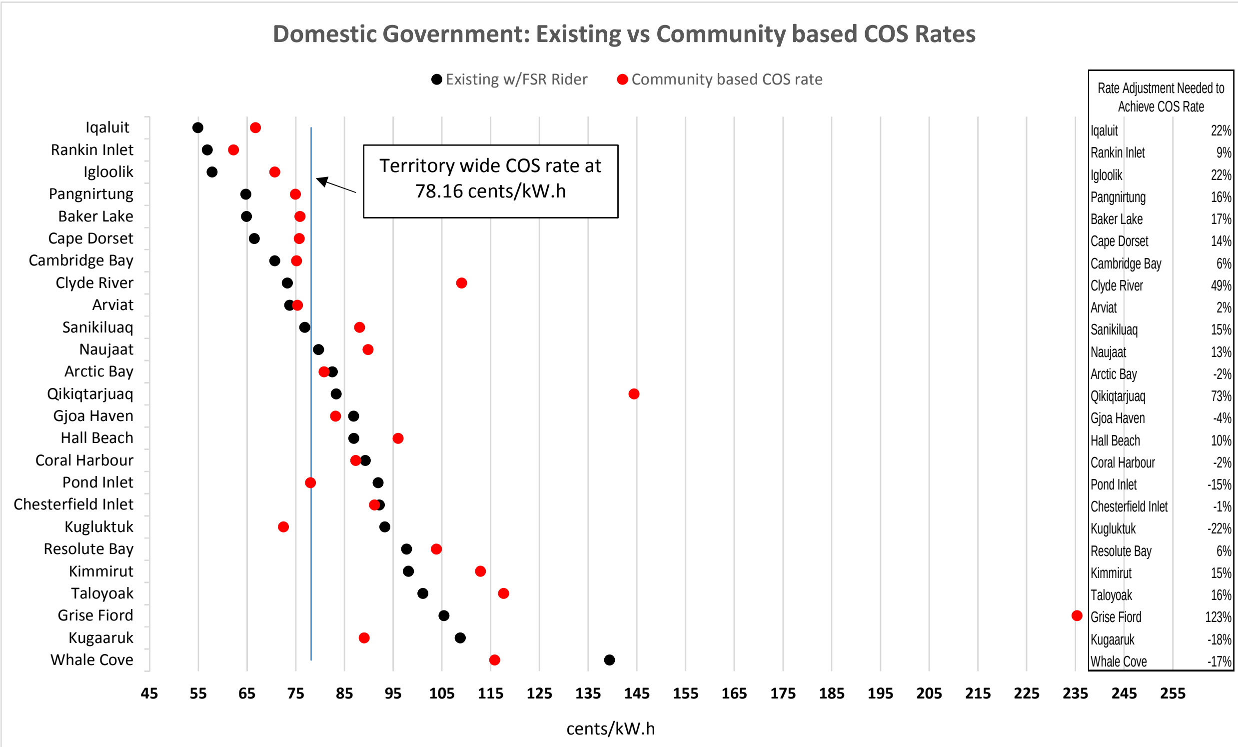


Figure 8.3:
Existing Rates Comparison to COS – Commercial Non-Government

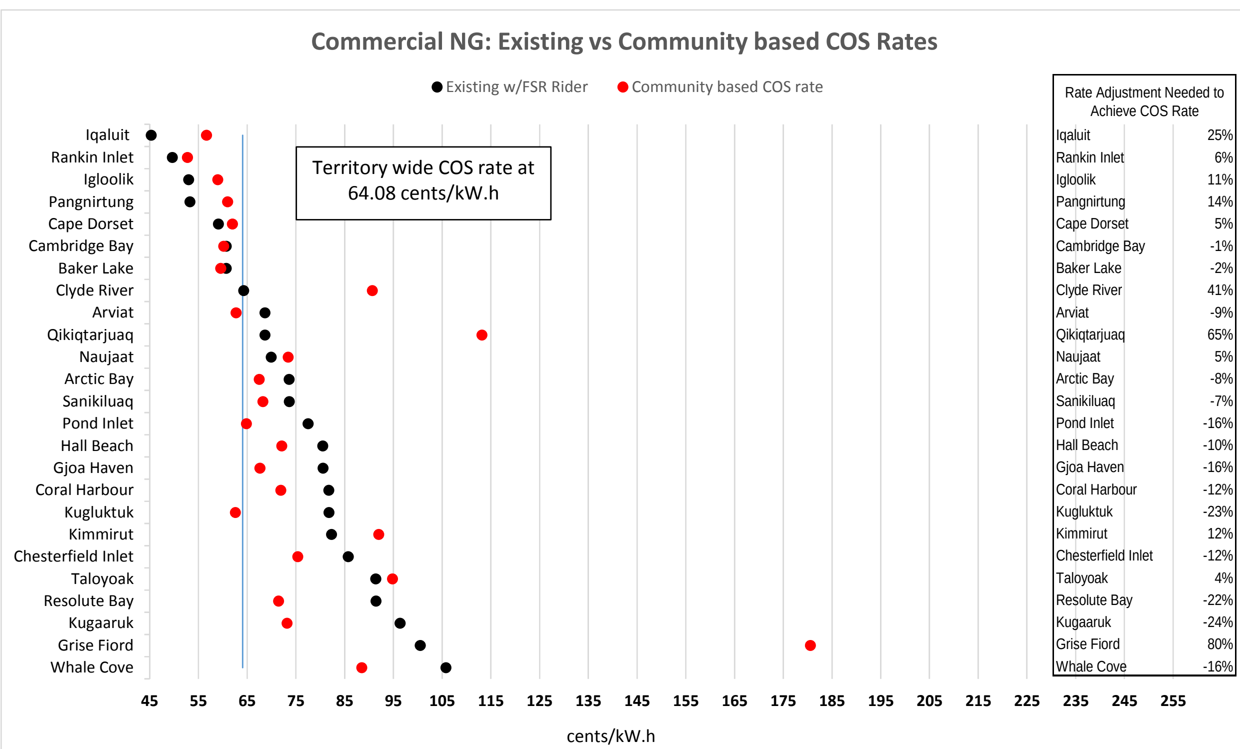
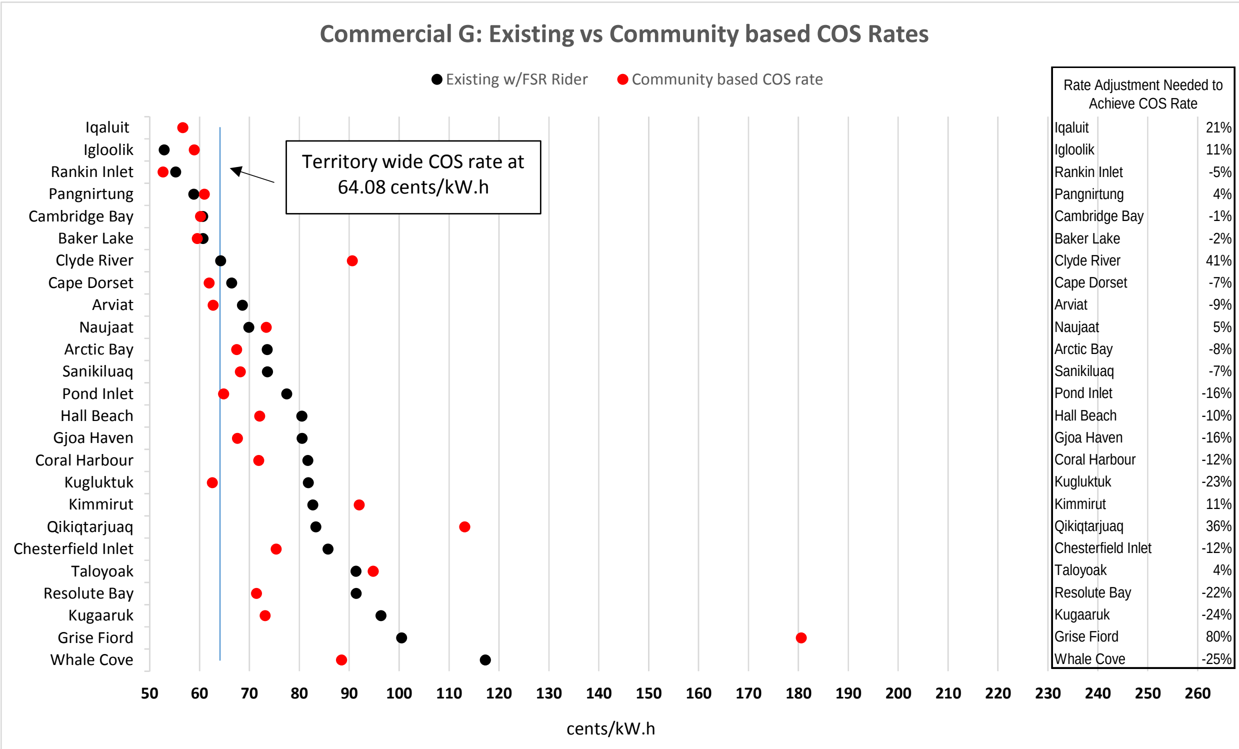


Figure 8.4:
Existing Rates Comparison to COS – Commercial Government



8.2.2 IMPACT OF HISTORICAL RATE ADJUSTMENTS ON COMMUNITY ENERGY RATES

The last COS based rates for Nunavut communities were approved effective March 29, 1999 by the Northwest Territories Public Utilities Board in Decision 2-99. Since then, rate adjustments have generally been implemented on an equal percentage basis across all rate classes with the following timeline:

- 16.5% rate increase effective April 1, 2005;
- 5.9% rate increase effective October 1, 2006;
- 18.9% rate increase effective April 1, 2011; and
- 7.1% rate increase effective May 1, 2014.

Table 8.1 shows the cumulative rate increase for non-government domestic and commercial rate classes in Iqaluit (a lower rate community) and Kugaaruk (one of the higher rate communities).

Table 8.1:
Historical Rate Increase Comparison

Community	Rates per NWT PUB Order 2-99	Rates Effective April 1, 2005	Rate Effective Oct. 1, 2006	Rates Effective April 1, 2011	Existing Rates Effective May 1, 2014	Cumulative Rate Increase Since Division
Rate Variance		16.5%	5.91%	18.88%	7.1%	
	cent/KWh	cent/KWh	cent/KWh	cent/KWh	cent/KWh	cent/kWh
	A	B	C	D	E	F=E-A
Domestic Non-Government						
Iqaluit	31.58	36.80	39.39	52.39	60.29	28.71
Kugaaruk	65.89	76.77	81.72	102.71	114.16	48.27
Commercial Non-Government						
Iqaluit	25.47	29.67	31.84	43.42	50.68	25.21
Kugaaruk	58.00	67.57	71.98	91.13	101.77	43.77

A review of Table 8.1 shows that while the rate adjustments were largely implemented on an equal percentage basis across all communities[31], the cumulative rate increases in absolute terms vary by community. The increase in Kugaaruk was nearly twice the increase in Iqaluit on a cents/kWh basis. As such, equal percentage rate adjustments put more burden on communities with relatively higher existing rates, which also are typically communities with smaller customer bases.

[31] The only exception when rate adjustments were implemented on a cents/kWh basis was on November 1, 2005 to implement capital stabilization-rebalancing levy rate riders.

8.2.3 IMPACT OF CAPITAL PROJECTS ON ENERGY RATES

Under a community-based rate structure, rate impacts for communities requiring substantial capital upgrades (e.g., power plant replacements or major distribution system upgrades) are very high. Table 8.2 illustrates this with the example of the Kugluktuk Power Plant project, which is currently under review by the URRC.

Table 8.2:
Kugluktuk New Power Plant Average Rate Impact Comparison

Capital Cost ($ 000)	31,436
Amortization Period (year)	40
GRA Approved Return on Ratebase	6.45%
Revenue Requirement Impacts	
Amortization Expense ($ 000)	786
Return on Ratebase ($ 000)	2,026
Less: Estimated Annual Fuel Savings	186
Revenue Requirement Increase	**2,626**
Kugluktuk 2021/22 Forecast Sales (MWh)	*5,470*
Average Community-Based Rate Increase (c/kWh)	48.01
Territorial 2021/22 Forecast Sales	*185,421*
Average Territorial Rate Increase (c/kWh)	1.42
Existing Kugluktuk Rate (c/kWh)	93.32
Rate increase under community-based approach	**51.4%**
Rate increase under Territory-wide approach	**1.5%**

As shown in Table 8.2, the rate impact for Kugluktuk under community-based rates would be 51.4%. This compares to a 1.5% increase for all ratepayers under the Territory-wide approach.

8.2.4 ALTERNATIVE ENERGY OPPORTUNITIES UNDER DIFFERENT RATE STRUCTURES

QEC is in the process of evaluating the feasibility of alternative energy projects. This has included undertaking wind energy studies and developing rate options like the net-metering program. Alternative energy projects can help reduce exposure to diesel fuel price volatility and reduce greenhouse gas emissions.

Due to the lack of an interconnected grid in Nunavut, alternative energy opportunities would only be able to directly service the communities where they are located. As such, under a community-based rate structure, the benefits of these projects would be limited only to the community where they are installed.

In contrast, a Territory-wide rate structure allows the benefits of alternative energy projects to be shared across all communities in Nunavut and benefit all Nunavummiut. This sharing of benefits also makes investment in such projects more attractive to territorial and federal government funders. Instead of investing capital dollars in a single community, capital investments in alternative energy would benefit customers across the Territory.

8.2.5 SUMMARY

QEC has reviewed rate options including maintaining the past practice of implementing rate adjustments on an equal percentage basis to all customers; rate rebalancing towards full community-based rates and rate rebalancing toward a single territory-wide rate zone. QEC is proposing to transition toward a single territory-wide rate zone for the following reasons:

- A comparison of the existing rates to the community-based COS rates shows that current rates are not reflective of a community-based cost of service study and that rebalancing to true community based rates would require rate increases of up to 172% for some customers. QEC simply does not feel this type of rate rebalancing is reasonable or feasible.

- The past practice of applying rate increases on an equal percentage basis has resulted in cumulative rate increases since 1999 that are substantially higher on a cents per kWh basis for communities like Kugaaruk compared to Iqaluit.

- A community based rate structure imposes substantial cost increases on communities that require significant reinvestment in generation and distribution assets. For example, the new power plant in Kugluktuk would require more than a 50% rate increase to recover the full cost of the project from the community, compared to a 1.5% increase if the costs are spread across a territory-wide rate structure.

- A territory-wide rate structure allows the benefits of investment in alternative energy projects to be shared across the territory. This also facilitates obtaining territorial and federal government funding, since capital investments benefit all Nunavummiut.

The Corporation recognizes the process of implementing a territory-wide rate structure will take some time, and therefore is proposing a six-year transition process. This application addresses the first two years of the six-year transition. The remaining four years of the transition will be addressed in a future application.

8.3 RATE DESIGN CRITERIA AND OBJECTIVES

Rate design is the process that determines the rates to be charged to each customer class. The process requires balancing a number of different and sometimes competing criteria. Cost causation, as measured by a COS study, is an important input into the rate design analysis. However the process also considers other economic, policy and administrative objectives.

The Corporation's rate design objectives for the 2018/19 GRA are:

1. **Rates must be set to recover revenue requirement.** The proposed total 2018/19 revenue to be recovered from rates is $131.500 million.

2. **Make progress toward Territory-wide rate zone (levelized rates).** The Corporation is recommending moving toward a territory-wide rate structure as discussed in Section 8.2.

3. **Move toward 95-105% revenue-cost coverage ratios for each rate class.** Based on QEC's Cost-of-service study, average rate increases would result in domestic and commercial rate classes having RCC ratios within the 95% to 105% zone of reasonableness that is typically accepted in Canadian jurisdictions. However the streetlighting rate class would have an RCC ratio of 83.7% if average rate increases were implemented. The Corporation proposes to set streetlighting rates as close as possible to 100% revenue-cost coverage ratio subject to a cap on rate rebalancing, which means that this class should receive higher than average rate increases, approximately 12.4% rate increases on average

4. **Focus rate adjustments on energy portion of the rate:** The Corporation is not proposing changes to the existing customer and demand charges, which are already levelized across the Territory.

5. **Phasing-in rate increase / decrease:** Section 5.3 of the Application notes that QEC filed an application with the Minister for a Fuel Rate Stabilization (FRS) refund rider of 5.41 cents/kWh effective October 1, 2017 to address ongoing variances between the 2014/15 GRA-approved and actual fuel prices, as well as to recover balances in the FRS fund. This refund rider will expire effective April 1, 2018. Elimination of this refund rider will increase the effective rates to customers on April 1, 2018, prior to considering the GRA rate adjustment impacts. In order to minimize rate impacts to customers, the Corporation adopted the following constraints on rate adjustments for all rate classes for the current application:

   i. **Revenue Requirement Phase-in:** QEC requires a 7.6% overall rate increase to recover the 2018/19 revenue requirement. The Corporation is proposing to phase-in the revenue lift required to achieve the full 2018/19 revenue requirement over two years – 2018/19 and 2019/20. The Corporation proposes to phase-in the rate increase by way of a 3.6% increase each year for the domestic and commercial rate classes and 12.4% in each year for the streetlighting rate class. The Corporation is forecasting the proposed 2018/19 rates will yield a return-on-equity of 5.18%, or $3.660 million lower than the full return on equity.

ii. **Rate Rebalancing:** Cap rate increases due to rebalancing to a maximum rate increase of 5% per year for rebalancing, over and above average revenue requirement increases; and

iii. **Proportional Rate Decreases:** Where a rate decrease is indicated, a maximum rate decrease per year proportional to the community's rate difference from the 100% COS rate.

6. **Phasing-in elimination of Government/Non-Government rate class distinction.** The elimination of government/non-government customer class distinctions was proposed in the 2010/11 GRA and was recommended for approval by the URRC in its Report 2012-01.[32] The URRC also recommended that QEC bring forward a rate change proposal in this regard at the time of the next GRA. In accordance with this recommendation, the Corporation has eliminated the distinction between government and non-government classes in the COS study. Proposed rate adjustments target the same average energy cost within the customer class for both government and non-government customers. Rate adjustments for the historic government rate classes are subject to the same constraints as for the non-government rate classes.

[32] URRC's report on QEC's 2010/11 Phase II GRA, 2012-01 dated from January 27, 2012, p.27.

8.4 2018/19 AND 2019/20 RATE PROPOSAL

Consistent with the rate design objectives outlined in section 8.3, the Corporation's proposed energy rates for the domestic and commercial rate classes effective April 1, 2018 and April 1, 2019 were developed based on the following steps:

- Step 1: Eliminate the FRS rider and compare the existing base energy rates to average territory-wide COS energy rates by rate class.
- Step 2: Where the existing base energy rates are below the levelized COS energy rates:
    i. If eliminating the FRS rider results in an effective rate increase of more than 8.6%, no further rate adjustment is made in Year 1 (2018/19). Year 2 (2019/20) rate increases are limited to 8.6% (3.6% revenue requirement increase plus 5% per year for rebalancing) or lower if two years of rate increases are sufficient to achieve the levelized cost-of-service rate.
    ii. Where elimination of the FRS rider results in the effective rate increase of less than 8.6%, limit the annual rate increase in Year 1 and Year 2 to the existing base energy rates plus FRS rider at 8.6% (3.6% revenue requirement increase plus 5% per for rebalancing) or lower if two years of rate increases are sufficient to achieve the levelized cost-of-service rate.
- Step 3: Balance the incremental revenue from Step 2 to reduce the rates in communities where rates are above the average COS energy rate. In this step the maximum rate decrease is proportional to each community's rate difference from

the COS rate. That is, rate classes that are further away from the COS-based rates receive a higher percentage rate decrease.

Under this approach, the maximum rate decrease for the current rate proposal is 4.9% per year, and it is applied in the communities which have the highest rate difference from the levelized COS rate. This proposal assists with a faster transition to territory-wide rates, by focussing rate decreases on the highest cost rate classes.

For the streetlighting rates, the following process was used:

- Step 1: Determine target revenues by community by increasing revenues until the full cost of service based revenues are achieved, subject to a maximum of 17.4% (the average increase required for streetlights of 12.4% plus a maximum of 5% for rate rebalancing). Capping rate increases at 17.4% results in a very small shortfall and therefore there is no ability to provide rate decreases to communities with revenues higher that levelized cost-based revenues at this time.

- Step 2: rebalance rates for different lamp types in each community to move closer to levelized cost-of-service based rates and achieve the target revenues calculated in step 1.

It is noted that currently QEC has active 250W HPS and 400W MV fixtures in only two communities and in very low quantities – one 250 HPS fixture in Kugluktuk and 18 in Iqaluit; two 400W MV fixtures in Cambridge Bay and one in Cape Dorset.

Streetlighting rate proposals include rates for light-emitting diode (LED) fixtures, which the Corporation is currently installing to replace high pressure sodium fixtures. LED rates are set equal to 100% of the levelized streetlighting cost-of-service rates.

Schedules 8.1 through 8.6 summarize the Corporation's rate proposals for 2018/19 and 2019/20 by rate class. Schedules 8.7.1-8.7.3 and 8.8.1-8.8.3 provide a proof of revenue calculation for 2018/19 and 2019/20 based on the proposed rates for each customer class.

8.5 FUTURE RATE TRANSITIONS

The transition to territory-wide rates will require 6-years to complete. This application addresses the first two-years of the transition. The remaining four years will be addressed in a future rate application.

Figures 8.5 through 8.8 illustrate the proposed revenue requirement adjustment and rate rebalancing based on the 2018/19 revenue requirement over the six-year period. Lines with circle markers indicate rate adjustments proposed for the current GRA. Lines without markers indicate illustrative rate adjustments that would be required in a future rate application. Actual rate adjustments for years beyond 2019/20 will be the subject of a future rate application.

Figure 8.5:
Proposed Rate Adjustments – Domestic Non-Government

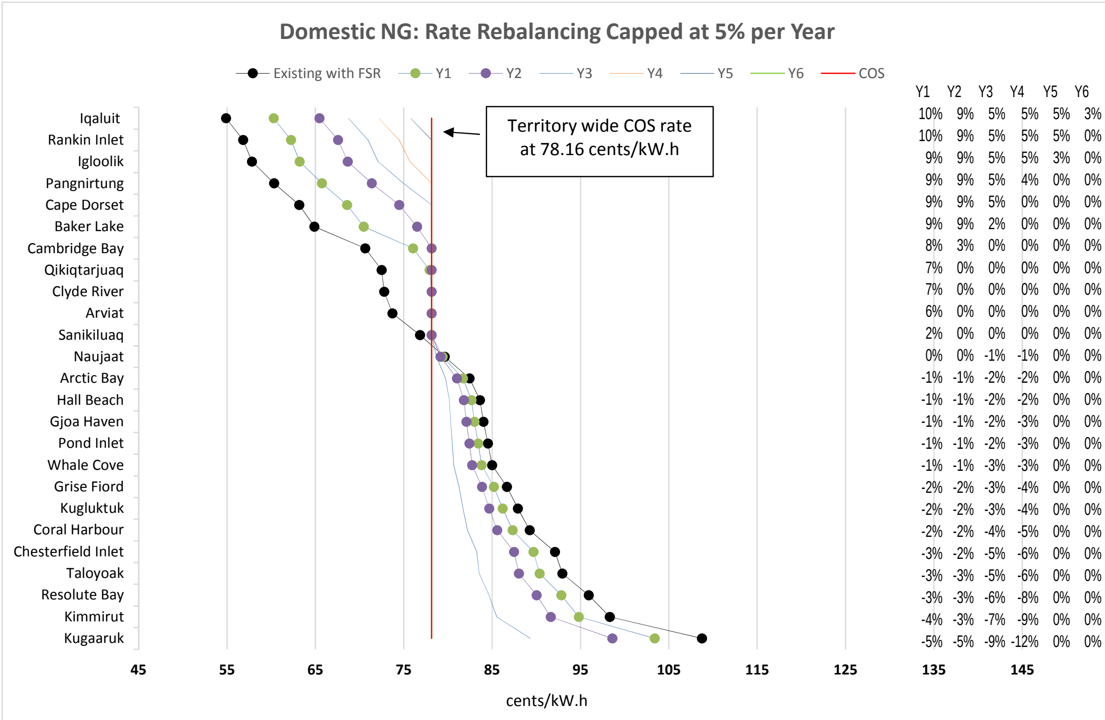


Figure 8.6:
Proposed Rate Adjustments – Domestic Government

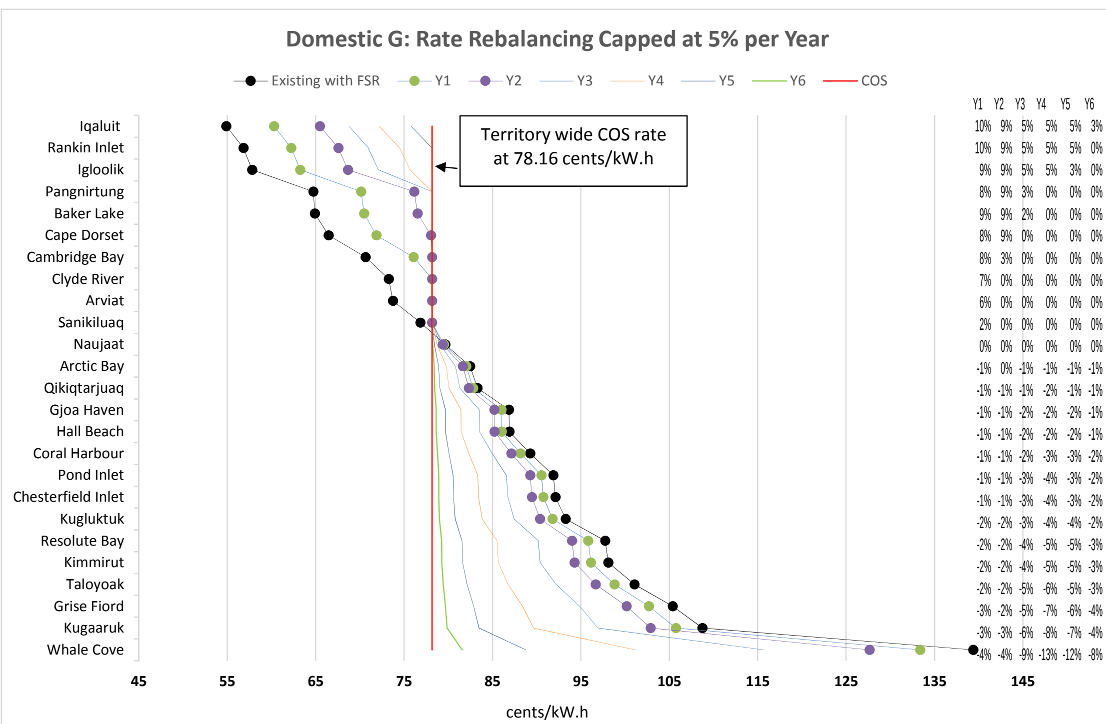


Figure 8.7:
Proposed Rate Adjustments – Commercial Non-Government

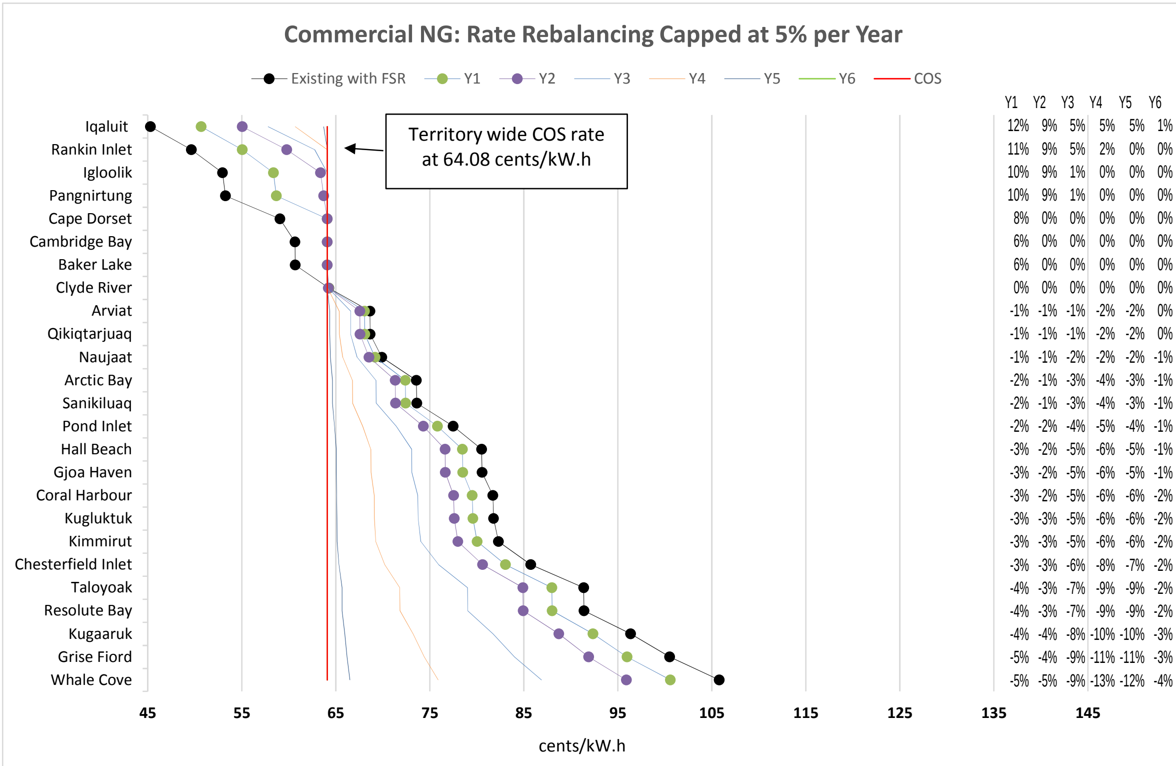


Figure 8.8:
Proposed Rate Adjustments – Commercial Government

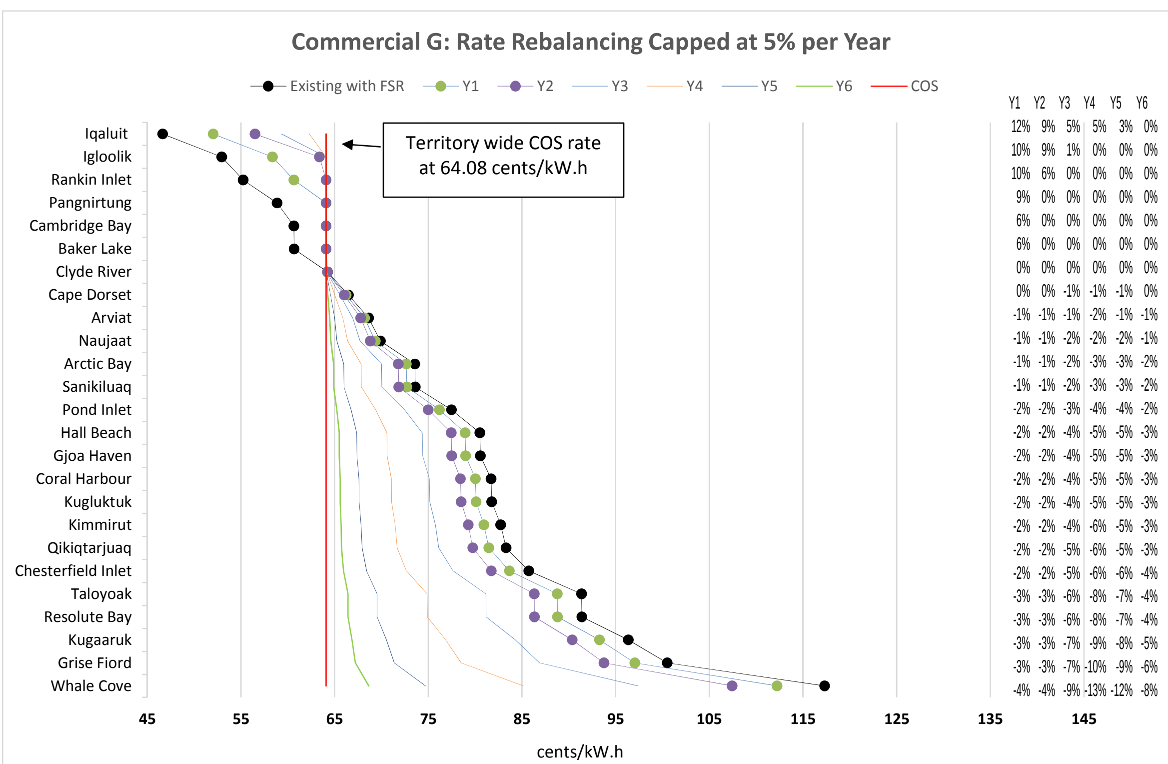


Table 8.3 compares the 2019/20 proposed rates to territory-wide COS rates by community to illustrate the further rate rebalancing required in future applications.

Table 8.3:
100% COS and 2019/20 Proposed Rates

	Domestic Non-Government			Domestic Government			Commercial Non-Government			Commercial Government		
	2019/20 Proposed Rates (cents/kWh)	COS Rate (cents/kWh)	Diff.	2019/20 Proposed Rates (cents/kWh)	COS Rate (cents/kWh)	Diff.	2019/20 Proposed Rates (cents/kWh)	COS Rate (cents/kWh)	Diff.	2019/20 Proposed Rates (cents/kWh)	COS Rate (cents/kWh)	Diff.
Cambridge Bay	78.16	78.16	0%	78.16	78.16	0%	64.08	64.08	0%	64.08	64.08	0%
Gjoa Haven	82.09	78.16	5%	85.20	78.16	9%	76.65	64.08	20%	77.49	64.08	21%
Taloyoak	88.04	78.16	13%	96.66	78.16	24%	84.91	64.08	33%	86.30	64.08	35%
Kugaaruk	98.60	78.16	26%	102.88	78.16	32%	88.72	64.08	38%	90.37	64.08	41%
Kugluktuk	84.68	78.16	8%	90.37	78.16	16%	77.59	64.08	21%	78.49	64.08	22%
Rankin Inlet	67.57	78.16	-14%	67.57	78.16	-14%	59.76	64.08	-7%	64.08	64.08	0%
Baker Lake	76.52	78.16	-2%	76.52	78.16	-2%	64.08	64.08	0%	64.08	64.08	0%
Arviat	78.16	78.16	0%	78.16	78.16	0%	67.55	64.08	5%	67.78	64.08	6%
Coral Harbour	85.57	78.16	9%	87.12	78.16	11%	77.53	64.08	21%	78.43	64.08	22%
Chesterfield Inlet	87.50	78.16	12%	89.45	78.16	14%	80.61	64.08	26%	81.71	64.08	28%
Whale Cove	82.74	78.16	6%	127.65	78.16	63%	95.90	64.08	50%	107.42	64.08	68%
Naujaat	79.16	78.16	1%	79.36	78.16	2%	68.51	64.08	7%	68.81	64.08	7%
Iqaluit	65.46	78.16	-16%	65.46	78.16	-16%	55.03	64.08	-14%	56.51	64.08	-12%
Pangnirtung	71.38	78.16	-9%	76.15	78.16	-3%	63.69	64.08	-1%	64.08	64.08	0%
Cape Dorset	74.48	78.16	-5%	78.04	78.16	0%	64.08	64.08	0%	66.02	64.08	3%
Resolute Bay	90.04	78.16	15%	93.99	78.16	20%	84.93	64.08	33%	86.33	64.08	35%
Pond Inlet	82.42	78.16	5%	89.25	78.16	14%	74.30	64.08	16%	74.98	64.08	17%
Igloolik	68.66	78.16	-12%	68.66	78.16	-12%	63.36	64.08	-1%	63.36	64.08	-1%
Hall Beach	81.81	78.16	5%	85.23	78.16	9%	76.61	64.08	20%	77.45	64.08	21%
Qikiqtarjuaq	78.16	78.16	0%	82.31	78.16	5%	67.57	64.08	5%	79.73	64.08	24%
Kimmirut	91.64	78.16	17%	94.28	78.16	21%	77.98	64.08	22%	79.26	64.08	24%
Arctic Bay	81.03	78.16	4%	81.64	78.16	4%	71.32	64.08	11%	71.80	64.08	12%
Clyde River	78.16	78.16	0%	78.16	78.16	0%	64.21	64.08	0%	64.22	64.08	0%
Grise Fiord	83.85	78.16	7%	100.16	78.16	28%	91.89	64.08	43%	93.75	64.08	46%
Sanikiluaq	78.16	78.16	0%	78.16	78.16	0%	71.35	64.08	11%	71.83	64.08	12%

A review of Figures 8.5 through 8.8 shows the following with respect to the transition to levelized rates by 2019/20:

- **Domestic Rate Class:**
    - o Non-government rates in five communities (Cambridge Bay, Qikiqtarjuaq, Clyde River, Arviat, and Sanikiluaq) achieve levelized territory-wide rates.
    - o Government rates in four communities (Cambridge Bay, Clyde River, Arviat, and Sanikiluaq) achieve levelized territory-wide rates.
    - o Non-government rates in seven communities (Gjoa Haven, Baker Lake, Naujaat, Cape Dorset, Pond Inlet, Hall Beach, and Arctic Bay) and government rates in six communities (Baker Lake, Naujaat, Pangnirtung,

  Qikiqtarjuaq, Cape Dorset and Arctic Bay) are at or below approximately 5% variance from levelized territory wide rates.

  - The maximum variance from the COS rate is 26% for non-government rates and 63% for government rates.

- **Commercial Rate Class:**
  - Non-government rates in three communities (Cambridge Bay, Baker Lake, and Cape Dorset) achieve levelized territory wide rates.
  - Government rates in four communities (Cambridge Bay, Rankin Inlet, Baker Lake, and Pangnirtung) achieve levelized territory wide rates by 2019/20.
  - Non-government rates in five communities (Arviat, Pangnirtung, Igloolik, Clyde River, and Qikiqtarjuaq) and government rates in three communities (Cape Dorset, Clyde River, and Igloolik) are at or below approximately 5% variance from levelized territory wide rates.
  - Maximum variance from COS rate is 50% for non-government rates and 68% for government rates.

Table 8.4 provides the RCC ratio by rate class under the 2019/20 proposed rates (full rates).

Table 8.4:
Cost of Service RCC Ratio under 2019/20 Proposed Rates

Customer Class	Revenue at 2019/20 Proposed Rates	COS Customer Class Revenue Requirement	Revenue Cost Coverage Ratio
	$000	$000	
Domestic	54,340	55,515	97.9%
Commercial	75,206	73,909	101.8%
Streetlighting	1,954	2,075	94.2%
Total	131,500	131,500	

Under the proposed full rates, RCC ratios change as follows as compared to an equal-percentage rate increase:

- Domestic rate class RCC ratio increases to 97.9% from 97.0% under an equal-percentage rate increase;
- Commercial rate class RCC ratio decreases to 101.8% from 102.7% under an equal-percentage rate increase; and
- Streetlighting customer class RCC ratio increases to 94.2% from 83.7% under an equal-percentage rate increase.

Schedule 8.1:
Rate Proposal – Domestic Non-Government

		Existing Base Rates	Fuel Rider	Existing Base Rates with Fuel Rider	Revenue Requirement and Rebalancing Phase-in: Remove FRS		Rate Proposal	2018/19 Proposed Energy Rates		2019/20 Phase-in and Rebalancing	
		c/kW.h	c/kW.h	c/kW.h	c/kW.h	% change	Domestic Non-Government	c/kW.h	Final % change	c/kW.h	Final % change
		A	B	C=A+B	D=A	E=D/C-1		F	G=F/C-1	H	G=H/F-1
	Target COS Rate				78.16						
701	Iqaluit	60.29	(5.41)	54.88	60.29	9.9%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	60.29	9.9%	65.46	8.6%
601	Rankin Inlet	62.23	(5.41)	56.82	62.23	9.5%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	62.23	9.5%	67.57	8.6%
706	Igloolik	63.23	(5.41)	57.82	63.23	9.4%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	63.23	9.4%	68.66	8.6%
702	Pangnirtung	65.74	(5.41)	60.33	65.74	9.0%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	65.74	9.0%	71.38	8.6%
703	Cape Dorset	68.59	(5.41)	63.18	68.59	8.6%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	68.59	8.6%	74.48	8.6%
602	Baker Lake	70.31	(5.41)	64.90	70.31	8.3%	Base rate below COS; increase below 8.6%. Limit increase to 8.6%.	70.47	8.6%	76.52	8.6%
501	Cambridge Bay	76.06	(5.41)	70.65	76.06	7.7%	Base rate below COS; increase below 8.6%. Limit increase to 8.6%.	76.06	7.7%	78.16	2.8%
708	Qikiqtarjuaq	77.92	(5.41)	72.51	77.92	7.5%	Base rate below COS; increase below 8.6%. Limit increase to 8.6%.	77.92	7.5%	78.16	0.3%
711	Clyde River	78.19	(5.41)	72.78	78.19	7.4%	Base rate above COS; rate decrease proportional to target COS.	78.16	7.4%	78.16	0.0%
603	Arviat	79.14	(5.41)	73.73	79.14	7.3%	Base rate above COS; rate decrease proportional to target COS.	78.16	6.0%	78.16	0.0%
713	Sanikiluaq	82.25	(5.41)	76.84	82.25	7.0%	Base rate above COS; rate decrease proportional to target COS.	78.16	1.7%	78.16	0.0%
607	Naujaat	85.06	(5.41)	79.65	85.06	6.8%	Base rate above COS; rate decrease proportional to target COS.	79.39	-0.3%	79.16	-0.3%
710	Arctic Bay	87.87	(5.41)	82.46	87.87	6.6%	Base rate above COS; rate decrease proportional to target COS.	81.71	-0.9%	81.03	-0.8%
707	Hall Beach	89.03	(5.41)	83.62	89.03	6.5%	Base rate above COS; rate decrease proportional to target COS.	82.67	-1.1%	81.81	-1.0%
502	Gjoa Haven	89.45	(5.41)	84.04	89.45	6.4%	Base rate above COS; rate decrease proportional to target COS.	83.02	-1.2%	82.09	-1.1%
705	Pond Inlet	89.95	(5.41)	84.54	89.95	6.4%	Base rate above COS; rate decrease proportional to target COS.	83.43	-1.3%	82.42	-1.2%
606	Whale Cove	90.42	(5.41)	85.01	90.42	6.4%	Base rate above COS; rate decrease proportional to target COS.	83.82	-1.4%	82.74	-1.3%
712	Grise Fiord	92.09	(5.41)	86.68	92.09	6.2%	Base rate above COS; rate decrease proportional to target COS.	85.20	-1.7%	83.85	-1.6%
505	Kugluktuk	93.32	(5.41)	87.91	93.32	6.2%	Base rate above COS; rate decrease proportional to target COS.	86.21	-1.9%	84.68	-1.8%
604	Coral Harbour	94.66	(5.41)	89.25	94.66	6.1%	Base rate above COS; rate decrease proportional to target COS.	87.32	-2.2%	85.57	-2.0%
605	Chesterfield Inlet	97.54	(5.41)	92.13	97.54	5.9%	Base rate above COS; rate decrease proportional to target COS.	89.70	-2.6%	87.50	-2.5%
503	Taloyoak	98.36	(5.41)	92.95	98.36	5.8%	Base rate above COS; rate decrease proportional to target COS.	90.37	-2.8%	88.04	-2.6%
704	Resolute Bay	101.35	(5.41)	95.94	101.35	5.6%	Base rate above COS; rate decrease proportional to target COS.	92.84	-3.2%	90.04	-3.0%
709	Kimmirut	103.74	(5.41)	98.33	103.74	5.5%	Base rate above COS; rate decrease proportional to target COS.	94.82	-3.6%	91.64	-3.4%
504	Kugaaruk	114.16	(5.41)	108.75	114.16	5.0%	Base rate above COS; rate decrease proportional to target COS.	103.42	-4.9%	98.60	-4.7%

Maximum of 8.6% is based on 3.6% increase for revenue requirement phase-in plus maximum of 5% rebalancing.

Schedule 8.2:
Rate Proposal – Domestic Government

		Existing Base Rates	Fuel Rider	Existing Base Rates with Fuel Rider	Revenue Requirement and Rebalancing Phase-in: Remove FRS		Rate Proposal	2018/19 Proposed Energy Rates		2019/20 Phase-in and Rebalancing	
		c/kW.h	c/kW.h	c/kW.h	c/kW.h	% change	Domestic Government	c/kW.h	Final % change	c/kW.h	Final % change
		A	B	C=A+B	D=A	E=D/C-1		F	G=F/C-1	H	G=H/F-1
	Target COS Rate				**78.16**						
701	Iqaluit	60.29	(5.41)	54.88	60.29	9.9%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	60.29	9.9%	65.46	8.6%
601	Rankin Inlet	62.23	(5.41)	56.82	62.23	9.5%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	62.23	9.5%	67.57	8.6%
706	Igloolik	63.23	(5.41)	57.82	63.23	9.4%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	63.23	9.4%	68.66	8.6%
702	Pangnirtung	70.13	(5.41)	64.72	70.13	8.4%	Base rate below COS; increase below 8.6%. Limit increase to 8.6%.	70.13	8.4%	76.15	8.6%
602	Baker Lake	70.31	(5.41)	64.90	70.31	8.3%	Base rate below COS; increase below 8.6%. Limit increase to 8.6%.	70.47	8.6%	76.52	8.6%
703	Cape Dorset	71.87	(5.41)	66.46	71.87	8.1%	Base rate below COS; increase below 8.6%. Limit increase to 8.6%.	71.87	8.1%	78.04	8.6%
501	Cambridge Bay	76.06	(5.41)	70.65	76.06	7.7%	Base rate below COS; increase below 8.6%. Limit increase to 8.6%.	76.06	7.7%	78.16	2.8%
711	Clyde River	78.67	(5.41)	73.26	78.67	7.4%	Base rate above COS; rate decrease proportional to target COS.	78.16	6.7%	78.16	0.0%
603	Arviat	79.14	(5.41)	73.73	79.14	7.3%	Base rate above COS; rate decrease proportional to target COS.	78.16	6.0%	78.16	0.0%
713	Sanikiluaq	82.25	(5.41)	76.84	82.25	7.0%	Base rate above COS; rate decrease proportional to target COS.	78.16	1.7%	78.16	0.0%
607	Naujaat	85.06	(5.41)	79.65	85.06	6.8%	Base rate above COS; rate decrease proportional to target COS.	79.50	-0.2%	79.36	-0.2%
710	Arctic Bay	87.87	(5.41)	82.46	87.87	6.6%	Base rate above COS; rate decrease proportional to target COS.	82.04	-0.5%	81.64	-0.5%
708	Qikiqtarjuaq	88.71	(5.41)	83.30	88.71	6.5%	Base rate above COS; rate decrease proportional to target COS.	82.79	-0.6%	82.31	-0.6%
502	Gjoa Haven	92.28	(5.41)	86.87	92.28	6.2%	Base rate above COS; rate decrease proportional to target COS.	86.01	-1.0%	85.20	-0.9%
707	Hall Beach	92.32	(5.41)	86.91	92.32	6.2%	Base rate above COS; rate decrease proportional to target COS.	86.05	-1.0%	85.23	-0.9%
604	Coral Harbour	94.66	(5.41)	89.25	94.66	6.1%	Base rate above COS; rate decrease proportional to target COS.	88.16	-1.2%	87.12	-1.2%
705	Pond Inlet	97.29	(5.41)	91.88	97.29	5.9%	Base rate above COS; rate decrease proportional to target COS.	90.53	-1.5%	89.25	-1.4%
605	Chesterfield Inlet	97.54	(5.41)	92.13	97.54	5.9%	Base rate above COS; rate decrease proportional to target COS.	90.76	-1.5%	89.45	-1.4%
505	Kugluktuk	98.68	(5.41)	93.27	98.68	5.8%	Base rate above COS; rate decrease proportional to target COS.	91.78	-1.6%	90.37	-1.5%
704	Resolute Bay	103.15	(5.41)	97.74	103.15	5.5%	Base rate above COS; rate decrease proportional to target COS.	95.81	-2.0%	93.99	-1.9%
709	Kimmirut	103.51	(5.41)	98.10	103.51	5.5%	Base rate above COS; rate decrease proportional to target COS.	96.14	-2.0%	94.28	-1.9%
503	Taloyoak	106.46	(5.41)	101.05	106.46	5.4%	Base rate above COS; rate decrease proportional to target COS.	98.80	-2.2%	96.66	-2.2%
712	Grise Fiord	110.79	(5.41)	105.38	110.79	5.1%	Base rate above COS; rate decrease proportional to target COS.	102.70	-2.5%	100.16	-2.5%
504	Kugaaruk	114.16	(5.41)	108.75	114.16	5.0%	Base rate above COS; rate decrease proportional to target COS.	105.74	-2.8%	102.88	-2.7%
606	Whale Cove	144.80	(5.41)	139.39	144.80	3.9%	Base rate above COS; rate decrease proportional to target COS.	133.36	-4.3%	127.65	-4.3%

Maximum of 8.6% is based on 3.6% increase for revenue requirement phase-in plus maximum of 5% rebalancing.

Schedule 8.3:
Rate Proposal – Commercial Non-Government

		Existing Base Rates	Fuel Rider	Existing Base Rates with Fuel Rider	Revenue Requirement and Rebalancing Phase-in						
					Remove FRS		Rate Proposal	2018/19 Proposed Energy Rates		2019/20 Phase-in and Rebalancing	
		c/kW.h	c/kW.h	c/kW.h	c/kW.h	% change	Commercial Non-Government	c/kW.h	Final % change	c/kW.h	Final % change
		A	B	C=A+B	D=A	E=D/C-1		F	G=F/C-1	H	G=H/F-1
	Target COS Rate				**64.08**						
701	Iqaluit	50.68	(5.41)	45.27	50.68	12.0%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	50.68	12.0%	55.03	8.6%
601	Rankin Inlet	55.04	(5.41)	49.63	55.04	10.9%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	55.04	10.9%	59.76	8.6%
706	Igloolik	58.35	(5.41)	52.94	58.35	10.2%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	58.35	10.2%	63.36	8.6%
702	Pangnirtung	58.66	(5.41)	53.25	58.66	10.2%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	58.66	10.2%	63.69	8.6%
703	Cape Dorset	64.47	(5.41)	59.06	64.47	9.2%	Base rate above COS; rate decrease proportional to target COS.	64.08	8.5%	64.08	0.0%
501	Cambridge Bay	66.07	(5.41)	60.66	66.07	8.9%	Base rate above COS; rate decrease proportional to target COS.	64.08	5.6%	64.08	0.0%
602	Baker Lake	66.09	(5.41)	60.68	66.09	8.9%	Base rate above COS; rate decrease proportional to target COS.	64.08	5.6%	64.08	0.0%
711	Clyde River	69.66	(5.41)	64.25	69.66	8.4%	Base rate above COS; rate decrease proportional to target COS.	64.23	0.0%	64.21	0.0%
603	Arviat	74.03	(5.41)	68.62	74.03	7.9%	Base rate above COS; rate decrease proportional to target COS.	68.06	-0.8%	67.55	-0.7%
708	Qikiqtarjuaq	74.06	(5.41)	68.65	74.06	7.9%	Base rate above COS; rate decrease proportional to target COS.	68.08	-0.8%	67.57	-0.8%
607	Naujaat	75.30	(5.41)	69.89	75.30	7.7%	Base rate above COS; rate decrease proportional to target COS.	69.17	-1.0%	68.51	-0.9%
710	Arctic Bay	78.97	(5.41)	73.56	78.97	7.4%	Base rate above COS; rate decrease proportional to target COS.	72.38	-1.6%	71.32	-1.5%
713	Sanikiluaq	79.01	(5.41)	73.60	79.01	7.4%	Base rate above COS; rate decrease proportional to target COS.	72.42	-1.6%	71.35	-1.5%
705	Pond Inlet	82.88	(5.41)	77.47	82.88	7.0%	Base rate above COS; rate decrease proportional to target COS.	75.81	-2.1%	74.30	-2.0%
707	Hall Beach	85.91	(5.41)	80.50	85.91	6.7%	Base rate above COS; rate decrease proportional to target COS.	78.46	-2.5%	76.61	-2.4%
502	Gjoa Haven	85.96	(5.41)	80.55	85.96	6.7%	Base rate above COS; rate decrease proportional to target COS.	78.50	-2.5%	76.65	-2.4%
604	Coral Harbour	87.11	(5.41)	81.70	87.11	6.6%	Base rate above COS; rate decrease proportional to target COS.	79.51	-2.7%	77.53	-2.5%
505	Kugluktuk	87.19	(5.41)	81.78	87.19	6.6%	Base rate above COS; rate decrease proportional to target COS.	79.58	-2.7%	77.59	-2.5%
709	Kimmirut	87.70	(5.41)	82.29	87.70	6.6%	Base rate above COS; rate decrease proportional to target COS.	80.03	-2.8%	77.98	-2.6%
605	Chesterfield Inlet	91.14	(5.41)	85.73	91.14	6.3%	Base rate above COS; rate decrease proportional to target COS.	83.04	-3.1%	80.61	-2.9%
503	Taloyoak	96.78	(5.41)	91.37	96.78	5.9%	Base rate above COS; rate decrease proportional to target COS.	87.98	-3.7%	84.91	-3.5%
704	Resolute Bay	96.81	(5.41)	91.40	96.81	5.9%	Base rate above COS; rate decrease proportional to target COS.	88.00	-3.7%	84.93	-3.5%
504	Kugaaruk	101.77	(5.41)	96.36	101.77	5.6%	Base rate above COS; rate decrease proportional to target COS.	92.35	-4.2%	88.72	-3.9%
712	Grise Fiord	105.92	(5.41)	100.51	105.92	5.4%	Base rate above COS; rate decrease proportional to target COS.	95.98	-4.5%	91.89	-4.3%
606	Whale Cove	111.18	(5.41)	105.77	111.18	5.1%	Base rate above COS; rate decrease proportional to target COS.	100.59	-4.9%	95.90	-4.7%

Maximum of 8.6% is based on 3.6% increase for revenue requirement phase-in plus maximum of 5% rebalancing.

Schedule 8.4:
Rate Proposal – Commercial Government

		Existing Base Rates	Fuel Rider	Existing Base Rates with Fuel Rider	Revenue Requirement and Rebalancing Phase-in: Remove FRS		Rate Proposal	2018/19 Proposed Energy Rates		2019/20 Phase-in and Rebalancing	
		c/kW.h	c/kW.h	c/kW.h	c/kW.h	% change	Commercial Government	c/kW.h	Final % change	c/kW.h	Final % change
		A	B	C=A+B	D=A	E=D/C-1		F	G=F/C-1	H	G=H/F-1
	Target COS Rate				**64.08**						
701	Iqaluit	52.04	(5.41)	46.63	52.04	11.6%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	52.04	11.6%	56.51	8.6%
706	Igloolik	58.35	(5.41)	52.94	58.35	10.2%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	58.35	10.2%	63.36	8.6%
601	Rankin Inlet	60.64	(5.41)	55.23	60.64	9.8%	Base rate below COS; increase above 8.6%. No further increase in 2018/19. Limit 2019/20 increase to 8.6%	60.64	9.8%	64.08	5.7%
702	Pangnirtung	64.26	(5.41)	58.85	64.26	9.2%	Base rate above COS; rate decrease proportional to target COS.	64.08	8.9%	64.08	0.0%
501	Cambridge Bay	66.07	(5.41)	60.66	66.07	8.9%	Base rate above COS; rate decrease proportional to target COS.	64.08	5.6%	64.08	0.0%
602	Baker Lake	66.09	(5.41)	60.68	66.09	8.9%	Base rate above COS; rate decrease proportional to target COS.	64.08	5.6%	64.08	0.0%
711	Clyde River	69.66	(5.41)	64.25	69.66	8.4%	Base rate above COS; rate decrease proportional to target COS.	64.23	0.0%	64.22	0.0%
703	Cape Dorset	71.87	(5.41)	66.46	71.87	8.1%	Base rate above COS; rate decrease proportional to target COS.	66.23	-0.3%	66.02	-0.3%
603	Arviat	74.03	(5.41)	68.62	74.03	7.9%	Base rate above COS; rate decrease proportional to target COS.	68.19	-0.6%	67.78	-0.6%
607	Naujaat	75.30	(5.41)	69.89	75.30	7.7%	Base rate above COS; rate decrease proportional to target COS.	69.34	-0.8%	68.81	-0.8%
710	Arctic Bay	78.97	(5.41)	73.56	78.97	7.4%	Base rate above COS; rate decrease proportional to target COS.	72.66	-1.2%	71.80	-1.2%
713	Sanikiluaq	79.01	(5.41)	73.60	79.01	7.4%	Base rate above COS; rate decrease proportional to target COS.	72.69	-1.2%	71.83	-1.2%
705	Pond Inlet	82.88	(5.41)	77.47	82.88	7.0%	Base rate above COS; rate decrease proportional to target COS.	76.19	-1.6%	74.98	-1.6%
707	Hall Beach	85.91	(5.41)	80.50	85.91	6.7%	Base rate above COS; rate decrease proportional to target COS.	78.94	-1.9%	77.45	-1.9%
502	Gjoa Haven	85.96	(5.41)	80.55	85.96	6.7%	Base rate above COS; rate decrease proportional to target COS.	78.98	-1.9%	77.49	-1.9%
604	Coral Harbour	87.11	(5.41)	81.70	87.11	6.6%	Base rate above COS; rate decrease proportional to target COS.	80.02	-2.1%	78.43	-2.0%
505	Kugluktuk	87.19	(5.41)	81.78	87.19	6.6%	Base rate above COS; rate decrease proportional to target COS.	80.09	-2.1%	78.49	-2.0%
709	Kimmirut	88.13	(5.41)	82.72	88.13	6.5%	Base rate above COS; rate decrease proportional to target COS.	80.94	-2.1%	79.26	-2.1%
708	Qikiqtarjuaq	88.71	(5.41)	83.30	88.71	6.5%	Base rate above COS; rate decrease proportional to target COS.	81.47	-2.2%	79.73	-2.1%
605	Chesterfield Inlet	91.14	(5.41)	85.73	91.14	6.3%	Base rate above COS; rate decrease proportional to target COS.	83.67	-2.4%	81.71	-2.3%
503	Taloyoak	96.78	(5.41)	91.37	96.78	5.9%	Base rate above COS; rate decrease proportional to target COS.	88.77	-2.8%	86.30	-2.8%
704	Resolute Bay	96.81	(5.41)	91.40	96.81	5.9%	Base rate above COS; rate decrease proportional to target COS.	88.80	-2.8%	86.33	-2.8%
504	Kugaaruk	101.77	(5.41)	96.36	101.77	5.6%	Base rate above COS; rate decrease proportional to target COS.	93.28	-3.2%	90.37	-3.1%
712	Grise Fiord	105.92	(5.41)	100.51	105.92	5.4%	Base rate above COS; rate decrease proportional to target COS.	97.04	-3.5%	93.75	-3.4%
606	Whale Cove	122.71	(5.41)	117.30	122.71	4.6%	Base rate above COS; rate decrease proportional to target COS.	112.23	-4.3%	107.42	-4.3%

Maximum of 8.6% is based on 3.6% increase for revenue requirement phase-in plus maximum of 5% rebalancing.

Schedule 8.5: 2018/19 Rate Proposal – Streetlights

	Existing Rates with FSR ($/month)					2018/19 Proposed Rates ($/month)							Change from Existing Rates						
	High Pressure Sodium		Mercury Vapour			High Pressure Sodium		Mercury Vapour			LED		High Pressure Sodium		Mercury Vapour			LED	
	100W	**250W**	**175W**	**250W**	**400W**	**100W**	**250W**	**175W**	**250W**	**400W**	**90W**	**210W**	**100W**	**250W**	**175W**	**250W**	**400W**	**90W**	**210W**
Cambridge Bay	38.66	62.96	38.36	47.42	62.31	43.43	104.35	45.01	101.16	161.50	31.94	74.54	12.3%	65.7%	17.4%	113.3%	159.2%		
Gjoa Haven	42.84	69.72	42.53	52.55	69.07	46.14	104.35	48.68	101.16	161.50	31.94	74.54	7.7%	49.7%	14.5%	92.5%	133.8%		
Taloyoak	58.66	95.62	58.36	72.14	94.97	58.66	104.35	60.41	101.16	161.50	31.94	74.54	0.0%	9.1%	3.5%	40.2%	70.1%		
Kugaaruk	48.31	78.69	48.00	59.32	78.04	48.51	104.35	58.36	101.16	161.50	31.94	74.54	0.4%	32.6%	21.6%	70.5%	106.9%		
Kugluktuk	61.32	100.01	61.01	75.49	99.36	61.32	104.35	61.01	101.16	161.50	31.94	74.54	0.0%	4.3%	0.0%	34.0%	62.5%		
Rankin Inlet	35.76	58.19	35.46	43.80	57.54	41.96	104.35	72.76	51.40	161.50	31.94	74.54	17.4%	79.3%	105.2%	17.4%	180.7%		
Baker Lake	36.07	58.68	35.77	44.20	58.03	42.33	104.35	72.76	51.87	161.50	31.94	74.54	17.4%	77.8%	103.4%	17.4%	178.3%		
Arviat	31.55	51.28	31.25	38.57	50.63	37.03	104.35	72.76	101.16	161.50	31.94	74.54	17.4%	103.5%	132.9%	162.3%	219.0%		
Coral Harbour	57.78	94.22	57.48	71.10	93.57	55.66	104.35	72.76	101.16	161.50	31.94	74.54	-3.7%	10.8%	26.6%	42.3%	72.6%		
Chesterfield Inlet	59.88	97.69	59.58	73.72	97.04	57.27	104.35	72.76	101.16	161.50	31.94	74.54	-4.4%	6.8%	22.1%	37.2%	66.4%		
Whale Cove	65.74	107.23	65.43	80.93	106.57	63.36	104.35	72.76	101.16	161.50	31.94	74.54	-3.6%	-2.7%	11.2%	25.0%	51.5%		
Repulse Bay	49.91	81.34	49.61	61.33	80.69	46.73	104.35	72.76	101.16	161.50	31.94	74.54	-6.4%	28.3%	46.7%	64.9%	100.2%		
Iqaluit	34.61	56.32	34.31	42.39	55.67	38.29	104.35	72.76	49.75	161.50	31.94	74.54	10.6%	85.3%	112.1%	17.4%	190.1%	N/A	N/A
Pangnirtung	32.64	53.08	32.34	39.96	52.43	38.31	104.35	72.76	46.89	161.50	31.94	74.54	17.4%	96.6%	125.0%	17.4%	208.0%		
Cape Dorset	42.96	69.92	42.66	52.72	69.27	44.23	104.35	72.76	101.16	161.50	31.94	74.54	2.9%	49.2%	70.6%	91.9%	133.1%		
Resolute Bay	84.75	138.34	84.45	104.50	137.69	84.75	104.35	72.76	104.50	161.50	31.94	74.54	0.0%	-24.6%	-13.8%	0.0%	17.3%		
Pond Inlet	62.12	101.29	61.82	76.45	100.64	62.12	104.35	72.76	78.66	161.50	31.94	74.54	0.0%	3.0%	17.7%	2.9%	60.5%		
Igloolik	43.26	70.45	42.96	53.09	69.80	46.14	104.35	72.76	66.02	161.50	31.94	74.54	6.6%	48.1%	69.4%	24.4%	131.4%		
Hall Beach	59.15	96.43	58.85	72.80	95.78	59.15	104.35	72.76	76.45	161.50	31.94	74.54	0.0%	8.2%	23.6%	5.0%	68.6%		
Qikiqtarjuaq	49.38	80.46	49.07	60.67	79.81	49.38	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	29.7%	48.3%	66.7%	102.4%		
Kimmirut	63.44	103.45	63.13	78.08	102.80	59.34	104.35	72.76	101.60	161.50	31.94	74.54	-6.4%	0.9%	15.3%	30.1%	57.1%		
Arctic Bay	49.66	80.93	49.35	61.02	80.28	49.66	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	28.9%	47.4%	65.8%	101.2%		
Clyde River	58.25	94.97	57.95	71.67	94.32	58.25	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	9.9%	25.6%	41.1%	71.2%		
Grise Fiord	71.02	115.84	70.71	87.49	115.19	69.55	104.35	72.76	101.16	161.50	31.94	74.54	-2.1%	-9.9%	2.9%	15.6%	40.2%		
Saniqiluaq	49.96	81.43	49.65	61.41	80.78	49.96	104.35	72.76	71.94	161.50	31.94	74.54	0.0%	28.1%	46.5%	17.1%	99.9%		

Schedule 8.6:
2019/20 Rate Proposal – Streetlights

	2018/19 Proposed Rates ($/month)					2019/20 Proposed Rates							Change from 2018/19 Proposed Rates						
	High Pressure Sodium		Mercury Vapour			High Pressure Sodium		Mercury Vapour			LED		High Pressure Sodium		Mercury Vapour			LED	
	100W	**250W**	**175W**	**250W**	**400W**	**100W**	**250W**	**175W**	**250W**	**400W**	**90W**	**210W**	**100W**	**250W**	**175W**	**250W**	**400W**	**90W**	**210W**
Cambridge Bay	43.43	104.35	45.01	101.16	161.50	43.43	104.35	61.25	101.16	161.50	31.94	74.54	0.0%	0.0%	36.1%	0.0%	0.0%	0.0%	0.0%
Gjoa Haven	46.14	104.35	48.68	101.16	161.50	46.14	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	49.5%	0.0%	0.0%	0.0%	0.0%
Taloyoak	58.66	104.35	60.41	101.16	161.50	46.14	104.35	72.76	101.16	161.50	31.94	74.54	-21.3%	0.0%	20.4%	0.0%	0.0%	0.0%	0.0%
Kugaaruk	48.51	104.35	58.36	101.16	161.50	46.14	104.35	72.76	101.16	161.50	31.94	74.54	-4.9%	0.0%	24.7%	0.0%	0.0%	0.0%	0.0%
Kugluktuk	61.32	104.35	61.01	101.16	161.50	52.30	104.35	72.76	101.16	161.50	31.94	74.54	-14.7%	0.0%	19.3%	0.0%	0.0%	0.0%	0.0%
Rankin Inlet	41.96	104.35	72.76	51.40	161.50	41.96	104.35	72.76	93.00	161.50	31.94	74.54	0.0%	0.0%	0.0%	80.9%	0.0%	0.0%	0.0%
Baker Lake	42.33	104.35	72.76	51.87	161.50	42.33	104.35	72.76	89.61	161.50	31.94	74.54	0.0%	0.0%	0.0%	72.8%	0.0%	0.0%	0.0%
Arviat	37.03	104.35	72.76	101.16	161.50	43.45	104.35	72.76	101.16	161.50	31.94	74.54	17.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coral Harbour	55.66	104.35	72.76	101.16	161.50	55.66	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Chesterfield Inlet	57.27	104.35	72.76	101.16	161.50	57.27	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Whale Cove	63.36	104.35	72.76	101.16	161.50	63.36	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Repulse Bay	46.73	104.35	72.76	101.16	161.50	46.73	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Iqaluit	38.29	104.35	72.76	49.75	161.50	38.29	104.35	72.76	69.09	161.50	31.94	74.54	0.0%	0.0%	0.0%	38.9%	0.0%	0.0%	0.0%
Pangnirtung	38.31	104.35	72.76	46.89	161.50	38.31	104.35	72.76	96.78	161.50	31.94	74.54	0.0%	0.0%	0.0%	106.4%	0.0%	0.0%	0.0%
Cape Dorset	44.23	104.35	72.76	101.16	161.50	46.14	104.35	72.76	101.16	161.50	31.94	74.54	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Resolute Bay	84.75	104.35	72.76	104.50	161.50	84.75	104.35	72.76	104.50	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Pond Inlet	62.12	104.35	72.76	78.66	161.50	46.14	104.35	72.76	101.16	161.50	31.94	74.54	-25.7%	0.0%	0.0%	28.6%	0.0%	0.0%	0.0%
Igloolik	46.14	104.35	72.76	66.02	161.50	46.14	104.35	72.76	83.90	161.50	31.94	74.54	0.0%	0.0%	0.0%	27.1%	0.0%	0.0%	0.0%
Hall Beach	59.15	104.35	72.76	76.45	161.50	46.14	104.35	72.76	101.16	161.50	31.94	74.54	-22.0%	0.0%	0.0%	32.3%	0.0%	0.0%	0.0%
Qikiqtarjuaq	49.38	104.35	72.76	101.16	161.50	49.38	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Kimmirut	59.34	104.35	72.76	101.60	161.50	59.34	104.35	72.76	101.60	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Arctic Bay	49.66	104.35	72.76	101.16	161.50	49.66	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Clyde River	58.25	104.35	72.76	101.16	161.50	58.25	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Grise Fiord	69.55	104.35	72.76	101.16	161.50	69.55	104.35	72.76	101.16	161.50	31.94	74.54	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Saniqiluaq	49.96	104.35	72.76	71.94	161.50	46.14	104.35	72.76	101.16	161.50	31.94	74.54	-7.6%	0.0%	0.0%	40.6%	0.0%	0.0%	0.0%

Schedule 8.7.1:
Base Rate Change and Proof of Revenue: 2018/19 Forecast Electricity Sales (MWh)

Plant No.	Plant Name	By Rate Class							Total Sales
		Domestic			Commercial			Streetlights	
		Non-Government	Government	Total	Non-Government	Government	Total		
		A	B	C=A+B	D	E	F=D+E	G	H=C+F+G
501	Cambridge Bay	1,843	1,827	3,670	5,174	3,422	8,595	123	12,388
502	Gjoa Haven	572	1,761	2,333	1,110	2,004	3,115	77	5,525
503	Taloyoak	332	1,387	1,718	872	1,070	1,942	56	3,717
504	Kugaaruk	376	1,108	1,484	503	733	1,236	31	2,752
505	Kugluktuk	905	1,663	2,568	1,225	1,704	2,928	66	5,562
601	Rankin Inlet	3,277	2,291	5,568	5,021	6,274	11,295	142	17,006
602	Baker Lake	1,408	2,411	3,819	2,009	2,329	4,337	111	8,268
603	Arviat	1,515	2,369	3,884	2,080	2,772	4,852	95	8,830
604	Coral Harbour	448	1,047	1,495	742	1,124	1,866	51	3,413
605	Chesterfield Inlet	209	515	724	619	566	1,184	26	1,934
606	Whale Cove	208	554	762	388	587	975	33	1,771
607	Naujaat	349	1,318	1,667	1,332	1,128	2,459	31	4,157
701	Iqaluit	13,529	5,135	18,665	21,680	16,301	37,981	419	57,065
702	Pangnirtung	744	1,803	2,547	1,323	2,018	3,341	141	6,029
703	Cape Dorset	619	1,630	2,248	1,020	1,948	2,968	76	5,292
704	Resolute Bay	269	320	589	1,095	2,068	3,162	40	3,791
705	Pond Inlet	791	1,859	2,650	1,296	2,085	3,380	113	6,144
706	Igloolik	815	1,947	2,762	1,227	2,475	3,702	95	6,559
707	Hall Beach	236	1,175	1,411	710	933	1,643	42	3,096
708	Qikiqtarjuaq	195	848	1,043	671	857	1,528	32	2,603
709	Kimmirut	212	528	740	459	588	1,047	33	1,820
710	Arctic Bay	356	1,177	1,533	535	899	1,434	34	3,001
711	Clyde River	423	1,435	1,858	468	1,157	1,625	25	3,509
712	Grise Fiord	117	199	316	200	476	676	23	1,015
713	Sanikiluaq	321	1,385	1,706	582	1,283	1,865	33	3,604
	Total	**30,068**	**37,695**	**67,763**	**52,339**	**56,800**	**109,139**	**1,949**	**178,851**

Schedule 8.7.2:
Base Rate Change and Proof of Revenue: 2018/19 Proposed Base Rates (cents/KWh)

Plant No.	Plant Name	Domestic		Commercial		Streetlights ($ per month per bulb)				
		Non-Government	Government	Non-Government	Government	HPS 100 watt (30 watt Ballast)	MV 175 watt (30 watt Ballast)	MV 250 watt (35 watt ballast)	HP 250 watt (44 watt ballast)	MV 400 watt (55 watt ballast)
		A	B	C	D	E	F	G	H	I
501	Cambridge Bay	76.06	76.06	64.08	64.08	43.43	45.01	101.16	104.35	161.50
502	Gjoa Haven	83.02	86.01	78.50	78.98	46.14	48.68	101.16	104.35	161.50
503	Taloyoak	90.37	98.80	87.98	88.77	58.66	60.41	101.16	104.35	161.50
504	Kugaaruk	103.42	105.74	92.35	93.28	48.51	58.36	101.16	104.35	161.50
505	Kugluktuk	86.21	91.78	79.58	80.09	61.32	61.01	101.16	104.35	161.50
601	Rankin Inlet	62.23	62.23	55.04	60.64	41.96	72.76	51.40	104.35	161.50
602	Baker Lake	70.47	70.47	64.08	64.08	42.33	72.76	51.87	104.35	161.50
603	Arviat	78.16	78.16	68.06	68.19	37.03	72.76	101.16	104.35	161.50
604	Coral Harbour	87.32	88.16	79.51	80.02	55.66	72.76	101.16	104.35	161.50
605	Chesterfield Inlet	89.70	90.76	83.04	83.67	57.27	72.76	101.16	104.35	161.50
606	Whale Cove	83.82	133.36	100.59	112.23	63.36	72.76	101.16	104.35	161.50
607	Naujaat	79.39	79.50	69.17	69.34	46.73	72.76	101.16	104.35	161.50
701	Iqaluit	60.29	60.29	50.68	52.04	38.29	72.76	49.75	104.35	161.50
702	Pangnirtung	65.74	70.13	58.66	64.08	38.31	72.76	46.89	104.35	161.50
703	Cape Dorset	68.59	71.87	64.08	66.23	44.23	72.76	101.16	104.35	161.50
704	Resolute Bay	92.84	95.81	88.00	88.80	84.75	72.76	104.50	104.35	161.50
705	Pond Inlet	83.43	90.53	75.81	76.19	62.12	72.76	78.66	104.35	161.50
706	Igloolik	63.23	63.23	58.35	58.35	46.14	72.76	66.02	104.35	161.50
707	Hall Beach	82.67	86.05	78.46	78.94	59.15	72.76	76.45	104.35	161.50
708	Qikiqtarjuaq	77.92	82.79	68.08	81.47	49.38	72.76	101.16	104.35	161.50
709	Kimmirut	94.82	96.14	80.03	80.94	59.34	72.76	101.60	104.35	161.50
710	Arctic Bay	81.71	82.04	72.38	72.66	49.66	72.76	101.16	104.35	161.50
711	Clyde River	78.16	78.16	64.23	64.23	58.25	72.76	101.16	104.35	161.50
712	Grise Fiord	85.20	102.70	95.98	97.04	69.55	72.76	101.16	104.35	161.50
713	Sanikiluaq	78.16	78.16	72.42	72.69	49.96	72.76	71.94	104.35	161.50

Schedule 8.7.3:
Base Rate Change and Proof of Revenue: Revenue Forecast at 2018/19 Proposed Rates ($000)

Plant No.	Plant Name	By Rate Class							Customer Charges and Demand Revenue			Total
		Domestic			Commercial			Streetlights	Customer Charges	Demand Revenue	Total	
		Non-Government	Government	Total	Non-Government	Government	Total					
		A	B	C=A+B	D	E	F=D+E	G	H	I	J=H+I	K=C+F+G+J
501	Cambridge Bay	*1,402*	*1,390*	2,791	*3,315*	*2,193*	5,508	99	*136*	*263*	400	8,798
502	Gjoa Haven	*475*	*1,515*	1,990	*872*	*1,583*	2,455	75	*73*	*116*	189	4,709
503	Taloyoak	*300*	*1,370*	1,670	*768*	*950*	1,717	59	*58*	*77*	135	3,581
504	Kugaaruk	*389*	*1,172*	1,561	*465*	*684*	1,149	31	*44*	*51*	95	2,835
505	Kugluktuk	*780*	*1,526*	2,306	*975*	*1,365*	2,339	74	*104*	*115*	219	4,938
601	Rankin Inlet	*2,039*	*1,426*	3,465	*2,763*	*3,805*	6,568	118	*205*	*359*	564	10,716
602	Baker Lake	*992*	*1,699*	2,691	*1,287*	*1,492*	2,779	91	*145*	*268*	413	5,975
603	Arviat	*1,184*	*1,852*	3,035	*1,415*	*1,890*	3,306	81	*149*	*198*	346	6,768
604	Coral Harbour	*392*	*923*	1,315	*590*	*900*	1,490	64	*58*	*69*	128	2,996
605	Chesterfield Inlet	*187*	*467*	655	*514*	*473*	987	34	*28*	*50*	78	1,753
606	Whale Cove	*175*	*739*	913	*390*	*659*	1,049	46	*28*	*53*	81	2,090
607	Naujaat	*277*	*1,048*	1,325	*921*	*782*	1,703	33	*51*	*81*	132	3,193
701	Iqaluit	*8,157*	*3,096*	11,253	*10,988*	*8,483*	19,470	286	*767*	*1,084*	1,851	32,860
702	Pangnirtung	*489*	*1,265*	1,754	*776*	*1,293*	2,070	110	*105*	*128*	233	4,166
703	Cape Dorset	*424*	*1,171*	1,596	*654*	*1,290*	1,944	77	*92*	*116*	208	3,824
704	Resolute Bay	*250*	*307*	556	*963*	*1,836*	2,799	55	*20*	*204*	224	3,634
705	Pond Inlet	*660*	*1,683*	2,343	*982*	*1,588*	2,571	119	*94*	*117*	211	5,243
706	Igloolik	*515*	*1,231*	1,747	*716*	*1,444*	2,160	75	*97*	*119*	216	4,198
707	Hall Beach	*195*	*1,011*	1,206	*557*	*737*	1,293	43	*43*	*169*	212	2,755
708	Qikiqtarjuaq	*152*	*702*	854	*457*	*698*	1,155	37	*44*	*77*	121	2,167
709	Kimmirut	*201*	*508*	709	*367*	*476*	843	43	*29*	*45*	74	1,668
710	Arctic Bay	*291*	*966*	1,257	*387*	*653*	1,040	39	*51*	*51*	103	2,438
711	Clyde River	*331*	*1,122*	1,453	*301*	*743*	1,044	34	*63*	*61*	124	2,655
712	Grise Fiord	*99*	*204*	304	*192*	*462*	654	31	*13*	*33*	46	1,035
713	Sanikiluaq	*251*	*1,083*	1,333	*421*	*933*	1,354	34	*54*	*67*	121	2,843
	Total	***20,606***	***29,476***	**50,081**	***32,036***	***37,412***	**69,448**	**1,788**	***2,551***	***3,971***	**6,523**	**127,840**

2018/19 Revenue Requirement	**134,047**	
Less: 2018/19 Non-electricity Revenue	**2,548**	
2018/19 Firm Rate Revenue Requirement		**131,500**
2018/19 Shortfall/(Surplus) at Proposed Rates		**(3,660)**

Schedule 8.8.1:
Base Rate Change and Proof of Revenue: 2018/19 Forecast Electricity Sales (MWh)

Plant No.	Plant Name	By Rate Class							Total Sales
		Domestic			Commercial			Streetlights	
		Non-Government	Government	Total	Non-Government	Government	Total		
		A	B	C=A+B	D	E	F=D+E	G	H=C+F+G
501	Cambridge Bay	1,843	1,827	3,670	5,174	3,422	8,595	123	12,388
502	Gjoa Haven	572	1,761	2,333	1,110	2,004	3,115	77	5,525
503	Taloyoak	332	1,387	1,718	872	1,070	1,942	56	3,717
504	Kugaaruk	376	1,108	1,484	503	733	1,236	31	2,752
505	Kugluktuk	905	1,663	2,568	1,225	1,704	2,928	66	5,562
601	Rankin Inlet	3,277	2,291	5,568	5,021	6,274	11,295	142	17,006
602	Baker Lake	1,408	2,411	3,819	2,009	2,329	4,337	111	8,268
603	Arviat	1,515	2,369	3,884	2,080	2,772	4,852	95	8,830
604	Coral Harbour	448	1,047	1,495	742	1,124	1,866	51	3,413
605	Chesterfield Inlet	209	515	724	619	566	1,184	26	1,934
606	Whale Cove	208	554	762	388	587	975	33	1,771
607	Naujaat	349	1,318	1,667	1,332	1,128	2,459	31	4,157
701	Iqaluit	13,529	5,135	18,665	21,680	16,301	37,981	419	57,065
702	Pangnirtung	744	1,803	2,547	1,323	2,018	3,341	141	6,029
703	Cape Dorset	619	1,630	2,248	1,020	1,948	2,968	76	5,292
704	Resolute Bay	269	320	589	1,095	2,068	3,162	40	3,791
705	Pond Inlet	791	1,859	2,650	1,296	2,085	3,380	113	6,144
706	Igloolik	815	1,947	2,762	1,227	2,475	3,702	95	6,559
707	Hall Beach	236	1,175	1,411	710	933	1,643	42	3,096
708	Qikiqtarjuaq	195	848	1,043	671	857	1,528	32	2,603
709	Kimmirut	212	528	740	459	588	1,047	33	1,820
710	Arctic Bay	356	1,177	1,533	535	899	1,434	34	3,001
711	Clyde River	423	1,435	1,858	468	1,157	1,625	25	3,509
712	Grise Fiord	117	199	316	200	476	676	23	1,015
713	Sanikiluaq	321	1,385	1,706	582	1,283	1,865	33	3,604
	Total	**30,068**	**37,695**	**67,763**	**52,339**	**56,800**	**109,139**	**1,949**	**178,851**

Schedule 8.8.2:
Base Rate Change and Proof of Revenue: 2019/20 Proposed Base Rates (cents/KWh)

Plant No.	Plant Name	Domestic		Commercial		Streetlights ($ per month per bulb)				
		Non-Government	Government	Non-Government	Government	HPS 100 watt (30 watt Ballast)	MV 175 watt (30 watt Ballast)	MV 250 watt (35 watt ballast)	HP 250 watt (44 watt ballast)	MV 400 watt (55 watt ballast)
		A	B	C	D	E	F	G	H	I
501	Cambridge Bay	78.16	78.16	64.08	64.08	43.43	61.25	101.16	104.35	161.50
502	Gjoa Haven	82.09	85.20	76.65	77.49	46.14	72.76	101.16	104.35	161.50
503	Taloyoak	88.04	96.66	84.91	86.30	46.14	72.76	101.16	104.35	161.50
504	Kugaaruk	98.60	102.88	88.72	90.37	46.14	72.76	101.16	104.35	161.50
505	Kugluktuk	84.68	90.37	77.59	78.49	52.30	72.76	101.16	104.35	161.50
601	Rankin Inlet	67.57	67.57	59.76	64.08	41.96	72.76	93.00	104.35	161.50
602	Baker Lake	76.52	76.52	64.08	64.08	42.33	72.76	89.61	104.35	161.50
603	Arviat	78.16	78.16	67.55	67.78	43.45	72.76	101.16	104.35	161.50
604	Coral Harbour	85.57	87.12	77.53	78.43	55.66	72.76	101.16	104.35	161.50
605	Chesterfield Inlet	87.50	89.45	80.61	81.71	57.27	72.76	101.16	104.35	161.50
606	Whale Cove	82.74	127.65	95.90	107.42	63.36	72.76	101.16	104.35	161.50
607	Naujaat	79.16	79.36	68.51	68.81	46.73	72.76	101.16	104.35	161.50
701	Iqaluit	65.46	65.46	55.03	56.51	38.29	72.76	69.09	104.35	161.50
702	Pangnirtung	71.38	76.15	63.69	64.08	38.31	72.76	96.78	104.35	161.50
703	Cape Dorset	74.48	78.04	64.08	66.02	46.14	72.76	101.16	104.35	161.50
704	Resolute Bay	90.04	93.99	84.93	86.33	84.75	72.76	104.50	104.35	161.50
705	Pond Inlet	82.42	89.25	74.30	74.98	46.14	72.76	101.16	104.35	161.50
706	Igloolik	68.66	68.66	63.36	63.36	46.14	72.76	83.90	104.35	161.50
707	Hall Beach	81.81	85.23	76.61	77.45	46.14	72.76	101.16	104.35	161.50
708	Qikiqtarjuaq	78.16	82.31	67.57	79.73	49.38	72.76	101.16	104.35	161.50
709	Kimmirut	91.64	94.28	77.98	79.26	59.34	72.76	101.60	104.35	161.50
710	Arctic Bay	81.03	81.64	71.32	71.80	49.66	72.76	101.16	104.35	161.50
711	Clyde River	78.16	78.16	64.21	64.22	58.25	72.76	101.16	104.35	161.50
712	Grise Fiord	83.85	100.16	91.89	93.75	69.55	72.76	101.16	104.35	161.50
713	Sanikiluaq	78.16	78.16	71.35	71.83	46.14	72.76	101.16	104.35	161.50

Schedule 8.8.3:
Base Rate Change and Proof of Revenue: Revenue Forecast at 2019/20 Proposed Rates ($000)

Plant No.	Plant Name	By Rate Class							Customer Charges and Demand Revenue			Total
		Domestic			Commercial			Streetlights	Customer Charges	Demand Revenue	Total	
		Non-Government	Government	Total	Non-Government	Government	Total					
		A	B	C=A+B	D	E	F=D+E	G	H	I	J=H+I	K=C+F+G+J
501	Cambridge Bay	*1,440*	*1,428*	2,868	*3,315*	*2,193*	5,508	116	*136*	*263*	400	8,892
502	Gjoa Haven	*470*	*1,501*	1,970	*851*	*1,553*	2,404	81	*73*	*116*	189	4,645
503	Taloyoak	*292*	*1,340*	1,632	*741*	*923*	1,664	60	*58*	*77*	135	3,491
504	Kugaaruk	*370*	*1,140*	1,511	*446*	*663*	1,109	33	*44*	*51*	95	2,748
505	Kugluktuk	*766*	*1,503*	2,269	*950*	*1,337*	2,288	74	*104*	*115*	219	4,849
601	Rankin Inlet	*2,214*	*1,548*	3,763	*3,001*	*4,021*	7,021	138	*205*	*359*	564	11,486
602	Baker Lake	*1,077*	*1,845*	2,922	*1,287*	*1,492*	2,779	107	*145*	*268*	413	6,222
603	Arviat	*1,184*	*1,852*	3,035	*1,405*	*1,879*	3,284	95	*149*	*198*	346	6,760
604	Coral Harbour	*384*	*912*	1,296	*575*	*882*	1,457	64	*58*	*69*	128	2,945
605	Chesterfield Inlet	*183*	*461*	643	*499*	*462*	961	34	*28*	*50*	78	1,716
606	Whale Cove	*172*	*707*	879	*372*	*631*	1,003	46	*28*	*53*	81	2,009
607	Naujaat	*276*	*1,046*	1,322	*912*	*776*	1,688	33	*51*	*81*	132	3,176
701	Iqaluit	*8,857*	*3,362*	12,219	*11,931*	*9,211*	21,141	336	*767*	*1,084*	1,851	35,547
702	Pangnirtung	*531*	*1,373*	1,904	*843*	*1,293*	2,136	130	*105*	*128*	233	4,403
703	Cape Dorset	*461*	*1,272*	1,733	*654*	*1,286*	1,940	81	*92*	*116*	208	3,960
704	Resolute Bay	*242*	*301*	543	*930*	*1,785*	2,715	55	*20*	*204*	224	3,536
705	Pond Inlet	*652*	*1,659*	2,311	*963*	*1,563*	2,526	121	*94*	*117*	211	5,168
706	Igloolik	*560*	*1,337*	1,897	*777*	*1,568*	2,345	89	*97*	*119*	216	4,546
707	Hall Beach	*193*	*1,002*	1,195	*544*	*723*	1,266	44	*43*	*169*	212	2,718
708	Qikiqtarjuaq	*152*	*698*	851	*453*	*683*	1,136	37	*44*	*77*	121	2,145
709	Kimmirut	*194*	*498*	692	*358*	*466*	824	43	*29*	*45*	74	1,633
710	Arctic Bay	*288*	*961*	1,249	*382*	*645*	1,027	39	*51*	*51*	103	2,418
711	Clyde River	*331*	*1,122*	1,453	*301*	*743*	1,044	34	*63*	*61*	124	2,654
712	Grise Fiord	*98*	*199*	297	*184*	*447*	630	31	*13*	*33*	46	1,004
713	Sanikiluaq	*251*	*1,083*	1,333	*415*	*922*	1,337	35	*54*	*67*	121	2,827
	Total	***21,639***	***30,150***	**51,789**	***33,088***	***38,147***	**71,234**	**1,954**	***2,551***	***3,971***	**6,523**	**131,500**

2018/19 Revenue Requirement	**134,047**	
Less: 2018/19 Non-electricity Revenue	**2,548**	
2018/19 Firm Rate Revenue Requirement		**131,500**
2019/20 Shortfall/(Surplus) at Proposed Rates		**0**

9.0 TERMS AND CONDITIONS OF SERVICE

The Corporation's terms and conditions of service were reviewed by the URRC during the 2014/15 GRA proceeding. QEC made certain revisions to the terms and conditions of service as recommended by the URRC in its Report 2014-05. The changes were accepted by the Minister in the Instruction dated May 30, 2014.

In this Application, the Corporation is proposing one change to its terms and conditions of service to add the following clause to Section 14.0 – Customer Responsibility and Liability:

14.10 Power Quality

> *Customers having non-linear load shall not be connected to QEC's distribution system unless power quality is maintained by implementing proper corrective measures such as installing proper filters, and/or grounding. Further, to ensure the distribution system is not adversely affected, power electronics equipment installed must comply with the latest version of IEEE Standard 519. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.*
>
> *If QEC determines the Customer's equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on QEC's distribution system, the Customer is obligated to help QEC*

> *by providing required equipment information, relevant data and necessary access for monitoring the equipment.*
>
> *If an undesirable system disturbance is being caused by the Customer's equipment, the Customer will be required to cease operation of the equipment until satisfactory remedial action has been taken by the Customer at the Customer's cost. If the Customer does not take such action within a reasonable time, QEC may disconnect the supply of power to the Customer.*

This change is necessary to ensure the Corporation can require customers to take remedial actions in cases where their operations are degrading power quality in a manner that adversely affects other customers or the Corporation's operations.

10.0 RESPONSE TO URRC RECOMMENDATIONS

10.1 INTRODUCTION

This chapter sets out the Corporation's responses to the directions and recommendations identified in the following URRC Reports:

- 2014-02: Grise Fiord Major Project Permit Application;
- 2014-04: 2014/15 GRA Draft Report (Phase I);[33] and
- 2012-01: 2010/11 Phase II GRA.

10.2 URRC REPORT 2014-02 GRISE FIORD MAJOR PROJECT PERMIT APPLICATION

Recommendation #2: The URRC recommends the prudence of the cost of construction of the project be examined at the time the project is proposed to be included in the rate base.

and

Recommendation #3: The URRC recommends QEC be directed to address the decommissioning and environmental cleanup plan for the existing site as well as the corresponding costs at the time the new Grise Fiord project is proposed to be included in rate base, and further, that site restoration and environmental cleanup

[33] The Minister's Instruction dated June 6, 2014 addressed only the recommendations in the URRC's final report 2014-05. The Minister did not instruct QEC to respond to the recommendations in URRC report 2014-04. However, QEC is providing the information it can on recommendations identified by the URRC in report 2014-04.

costs be reflected in the annual amortization rates and amortization expense for regulatory purposes.

QEC Response:

QEC has provided information related to this project in Chapter 6 of this Application. QEC is proposing to address site restoration costs by way of an annual operations and maintenance expense provision as described in Chapter 4 of the Application.

10.3 URRC REPORT 2014-4 2014/15 GRA

Recommendation #1: QEC is directed to implement the following changes to improve project costing and management practices:

- **Establish a plus or minus 20% MPPA project costing threshold that will trigger a review of the project expenses by QEC's governing body as soon as QEC becomes aware that it will exceed these thresholds; this would require an appropriate level of due diligence work on scoping and preparation of cost estimates.**
- **Implement effective due diligence efforts including full completion of internal estimates of contractor costs prior to contract negotiations to mitigate the risk of high contract bids and surprises, particularly where there are limited number of qualified bidders within the local marketplace.**

- **Commence with the following project controls for the approved MPPAs for the Taloyoak, Qikiqtarjuaq and Grise Fiord power plants and all subsequent MPPAs:**
    - **Develop and implement effective procedures for monitoring, reporting, variance analysis and control of project costs and documentation of the outcome of these activities at every stage of project planning, development and implementation;**
    - **Prepare post completion reports summarizing the documented activities related to project monitoring, reporting, variance analysis and control of project costs; and**
    - **Implement accountability measures including clear lines of responsibility and accountability for economic, efficient and effective planning and execution of capital projects.**

QEC's Response:

In response to this recommendation, QEC initiated a process in 2015 to review and update the Corporation's capital planning and project management system. As part of this process, QEC:

- Updated capital project brief template and instructions to ensure they are consistent with the QEC standards and the URRC recommendations;

- Established a Capital Planning Committee (CPC) responsible for the general oversight of the capital planning and management at QEC; and
- Developed capital planning and project management manual.

The processes and procedures as outlined in the manual serve as QEC's guiding principles when undertaking capital planning activities. The manual is organized into two sections: 1) Capital Planning and 2) Capital Project Management.

The capital planning process focuses on all capital projects and occurs in two phases:

1) Resource Planning for Major Capital Projects: this is a process undertaken at least every four years, and updated from time to time as necessary, to identify and prioritize major capital projects. The purpose of the resource planning process is to identify major capital projects that typically require substantial lead time to plan, obtain approval from the responsible Minister, construct, and require substantial capital investment.

2) Near and Longer Term Planning Phase: this phase involves preparation of two distinct products on an annual basis:

    a. Annual Capital Plan: this task involves preparation of project briefs and development and approval of QEC's annual capital plan and budget. The Annual Capital Plan is an operative plan defining project budgets for the upcoming fiscal year. For multi-year projects, the budget for each year of the project is included and approved in the annual capital plan.

b. 10-year Capital Plan: this is the process of slating the major capital projects identified from the resource planning, including core replacement/improvement capital projects into a ten year capital schedule. The 10-year capital plan is reviewed on an annual basis, and the proposed projects are prioritized for years one and two, consistent with the resource plan. Projects are re-evaluated each year to determine if value or risk has changed, and the 10-year capital plan is revised accordingly.

The capital project management process is project specific and includes four phases:

1) <u>Project Initiation (Planning) Phase</u>: this phase involves assignment of a project manager and developing a more detailed scope, budget and objectives for the Project.

2) <u>Design and Tendering Phase</u>: this phase involves contract tendering, evaluation and award.

3) <u>Implementation and Construction Phase</u>: this phase involves the implementation and construction of approved capital projects.

4) <u>Project Closeout Phase</u>: this phase involves commissioning and final accounting of capital projects.

The capital planning committee has been mandated to give direction and recommendations on capital planning and project management as required and will recommend amendments to the manual if the need arises.

Recommendation #2: URRC directs QEC to take immediate steps to institute procedures to identify and retire assets that are no longer in service. Once such procedures are instituted retirements should be reflected in the actual results and test year forecasts.

QEC's Response:

QEC has a procedure to identify and retire assets no longer in service. QEC has retired assets with original cost totaling $0.640 million in 2012/13, $0.422 million in 2013/14, $0.313 million in 2014/15, and $5.319 million in 2015/16, plus an additional $3.197 million due to fire in Pangnirtung.

QEC's operation department assembles a list of assets that are no longer in service. This information is reviewed internally between QEC departments. Assets with net book value more than $20,000 are retired only after approval from the Nunavut Financial Management Board, while assets with net book value less than $20,000 are retired based on QEC's Board's approval.

Recommendation #3: QEC is directed to examine the appropriate regulatory treatment of interim retirements during major overhaul of diesel plant and report the findings at the next GRA.

QEC's Response:

Concentric reviewed QEC's practice related to engine overhauls and notes that it will not result in customers paying for the amortization of any investment twice. Even though the original investment in the replaced component parts are not retired from property, plant, and equipment at the time of engine overhauls, there is no over-recovery or double recovery of any capital investment. QEC's practice results in the appropriate level of depreciation and amortization expense to reflect the average service life estimate of investment and furthermore results in the correct level of rate base used in the development of customer tolls.

Recommendation #4: For the next GRA, URRC directs QEC to consider the following refinements to its forecast method:

- **Customer count forecast to be determined taking into consideration independent drivers of customer growth such as Housing starts, GDP growth, Population growth forecasts, Average customer growth in the past 3 years and known commercial customer additions, all as may be relevant and as applicable to QEC's service territory.**
- **Regression analysis to be used to forecast usage per customer rather than to total sales.**

QEC's Response:

In 2015/16, QEC completed a review of its load forecast methods with the following objectives:

1. Gather necessary information in order to be able to address the URRC recommendation regarding load forecast method refinements for the next GRA; and

2. Select a load forecast method for QEC that provides reliable results while remaining practical to implement (in terms of data availability and required level of effort to run the model and prepare a load forecast).

As part of this review, the Corporation analyzed the performance of the following load forecast methods as used by QEC and other northern utilities (NTPC, YECL and Northland Utilities Ltd.):

1. Load forecast method based on trend and weather regression analysis;
2. Usage per customer (UPC) method based on regression model under normalized weather; and
3. UPC method based on prior years rolling average.

Based on the load forecast performance and data analysis, QEC conducted the evaluation of the load forecast methods by the following criteria:

- Data availability;
- Forecast reliability and accuracy; and
- Implementation complexity.

Based on the evaluation, QEC selected the UPC method based on prior years rolling average as the preferred option as it best meets overall evaluation criteria, in terms of data availability, forecast reliability, and implementation complexity.

The UPC based load forecast method was adopted by QEC starting from the 2016/17 period for purposes of operating budget preparations, fuel stabilization fund updates, and capital planning and budgeting.

As such, the load forecast for this Application was prepared using the UPC-based load forecast method. Forecast UPC is based on a rolling average for the most recent five-year actual UPC. The number of customers are increased taking into account a five-year actual population growth trend for each community.

Recommendation #5: In Report 2011-01 the URRC provided the following direction:

> **If forecast earnings for a prospective year are higher or lower than the rate of return on equity plus or minus 200 basis points, a rate application should be triggered by QEC. The URRC considers GRA applications triggered by this mechanism should be submitted prior to the commencement of the relevant Test Year to be in compliance with the forward Test Year principle.**

The URRC considers the above direction relevant and applicable to the timing of all future General Rate Applications. It is therefore re-issued as a direction for future.

QEC's Response:

The response from the Minister dated May 26, 2011 to the URRC's Report 2010-01 (March 2, 2011) and brought up as a direction in the next GRA in URRC Report

2014-04 (April 28, 2014) noted that the Corporation plans to file rate applications in three year intervals. QEC's current application is consistent with that schedule. This process is being considered in order to avoid material gaps between rate application reviews. This will be much easier to monitor than the 200 basis point return on equity trigger suggestion while addressing the concerns of filing applications in a more timely fashion. Wherever feasible, QEC intends to provide future rate applications in advance of the relevant test year.

Recommendation #6: QEC is directed to provide details of how the capitalized overhead rate is determined, consistent with the PSA accounting standard, at the time of the next GRA.

QEC's Response:

QEC applies a 9% average overhead rate to capital projects, consistent with the practice in previous years.

Recommendation #7: The URRC directs QEC to address the matter of future removal and site restoration costs and/or asset retirement obligations, as may be applicable, as soon as possible and reflect the findings in the next amortization study.

QEC's Response:

QEC has completed an amortization study that addresses future removal and site restoration costs and asset retirement obligations. The results of the study are reflected in the calculation for amortization expense for the 2018/19 test year.

Recommendation #8: In its 2004/05 GRA Report the URRC stated:

> *The URRC also considers, consistent with the practice in other jurisdictions, the revenues and costs resulting from industrial contracts should be included in the Corporation's revenue requirement and revenues and must be subject to review at the time of QEC's subsequent GRAs. The URRC considers any contractual rates established with large industrial customers should reflect the principles of cost causation, including an allocation of shared costs. QEC is directed to reflect the foregoing principles in any future filings and in contractual arrangements with large industrial customers.*

QEC is directed to continue to reflect the above principles in the development of industrial rates.

QEC's Response:

QEC currently has no industrial customers and does not anticipate having any industrial customers in the 2018/19 test year. QEC will consider the rate design principles described by the URRC in preparing an application for future industrial customers.

Recommendation #9: The URRC considers the following additional information based on standardized CAIDI, SAIDI and SAIFI statistics may provide better context respecting outage statistics for future proceedings:

- **QEC's historical reliability performance over 3 historical years preceding the test year including charts;**

- **Historical reliability statistics of Canadian Off Grid Utilities Association (COGUA) members and other Canadian Utilities, over a comparable period as for QEC; and**
- **Explanations for major changes in QEC's reliability statistics from one year to the next having regard to most prominent events.**

The URRC directs QEC to provide the above noted information at the time of the next GRA.

QEC's Response:

Table 10.1 and Figure 10.1 show QEC's historic SAIDI, SAIFI and CAIFI indicators for fiscal years ending 2014 through 2017. Average SAIDI and SAIFI information is also provided for Northern Utilities including Yukon Electrical, Yukon Energy, Northwest Territories Power Corporation, Northland Utilities (Yellowknife), Northland Utilities (NWT) and QEC. Comparison information is only available through 2016 and the Canadian Electrical Association does not publish information for individual utilities. Comparable information for CAIDI was not available.

The data show that QEC performed better than the average of the other utilities for both SAIDI and SAIFI in two out of the three years. Key factors in the years where reliability indicators were poorer than the average of northern utilities include:

- Adverse weather in the Baffin region resulted in significant outages in January 2014. Iqaluit experienced a wind storm with gusts of up to 150 km/hour.

- Loss of supply issues, particularly in Hall Beach, Baker Lake and Sanikiluaq.

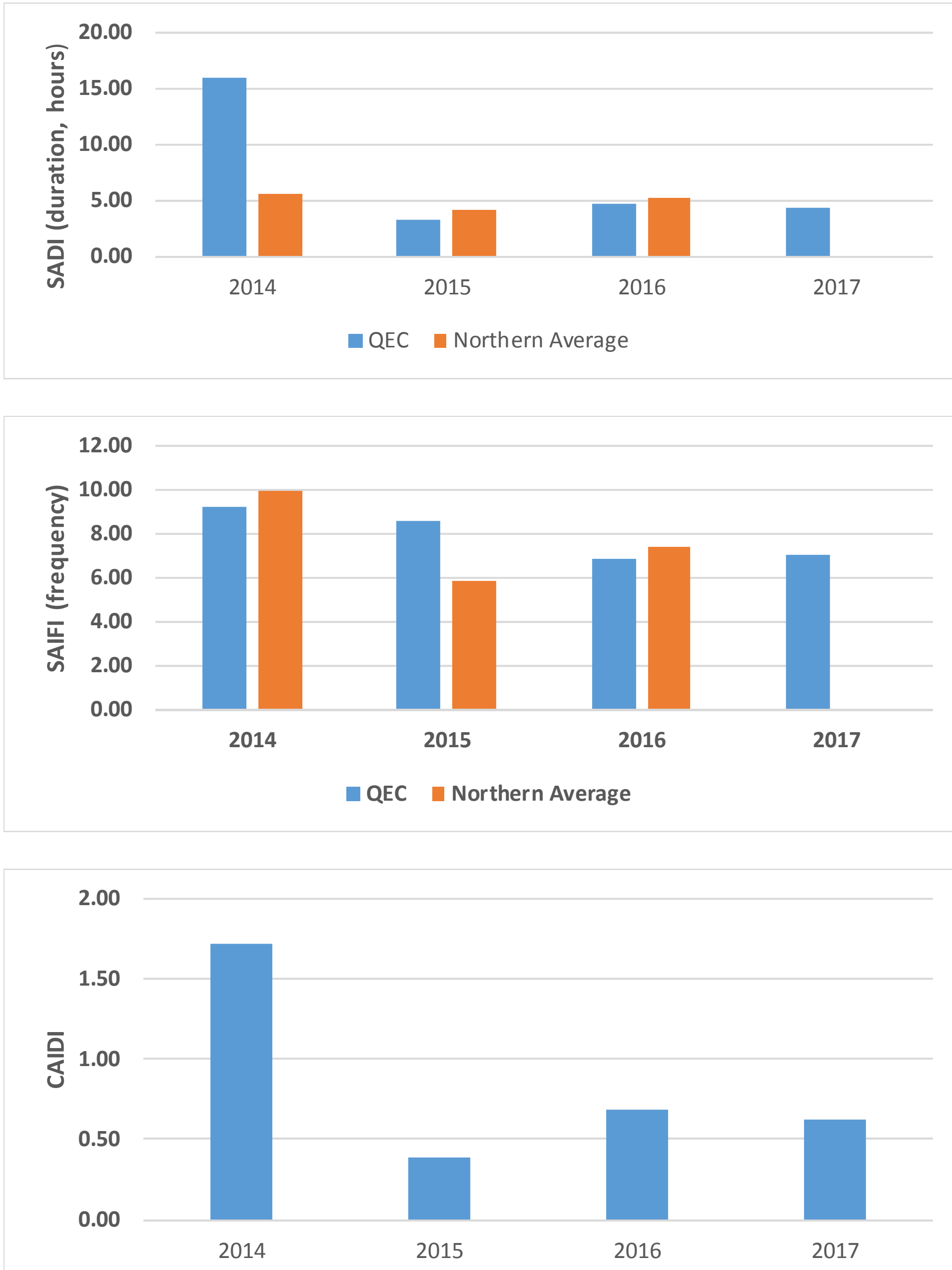
Table 10.1:
2014 through 2017 SAIDI, SAIFI and CAIDI Indicators

SAIDI	2014	2015	2016	2017
QEC	15.87	3.28	4.59	4.32
Northern Average	5.57	4.12	5.19	

SAIFI	2014	2015	2016	2017
QEC	9.23	8.59	6.80	6.97
Northern Average	9.94	5.87	7.35	

CAIDI	2014	2015	2016	2017
QEC	1.72	0.38	0.68	0.62

Figure 10.1:
2014 through 2017 SAIDI, SAIFI and CAIDI



Recommendation #10: The URRC directs QEC to provide the information on worker injury rates comparable to Table 11-2 and Table 4 of URRC QEC 26d) at the next GRA.

QEC's Response:

Please refer to Table 10.2. A lost time injury is defined as any work-related injury that results in a company employee or third-party contractor employee not being able to return to work the next scheduled work day.

The injury severity rate describes the number of lost work days experienced per 100 workers, it is calculated as:

(actual # of lost workdays) x (200,000 hours) / actual total # of hours worked by all employees.

The injury frequency rate shows the total number of lost time injuries experienced per 100 workers. The injury frequency rate is calculated as:

(# of lost time injuries) x (200,000 hours) / actual total # of hours worked by all employees.

Table 10.2:
Actual Worker Injury and Severity Rates for 2013/14 through 2015/16

	2013/14	2014/15	2015/16
Injury Severity Rate			
QEC	3.80	90.77	95.87
MB Hydro	11.10	6.60	12.51
BC Hydro	28.90	23.30	30.00
NTPC	13.36	32.49	5.98
Injury Frequency Rate			
QEC	1.17	2.54	3.07
MB Hydro	0.70	0.40	0.59
BC Hydro	2.30	2.36	2.02
NTPC	N/A	N/A	N/A

The Corporation's higher injury rates in 2014/15 and 2015/16 relate in particular to two incidents that required prolonged medical leave in the south, as well as a graduated return to work schedule

Recommendation #11: The URRC directs QEC to consult with its customers in designing and developing service quality measures and proceed with implementation without further delay. QEC is also directed to report customer service metrics reflecting customer service performance from fiscal year 2014/15 on, at the time of the next GRA.

QEC's Response:

QEC has been undertaking customer satisfaction surveys at regular intervals since October 2015. The telephone surveys are performed by an independent third party. Interviews are available in English and Inuktitut. Key findings from the most recent survey and comparisons with previous results are provided under the following headings.

Reputation

- Just over half (55%) of respondents had a positive ***impression of QEC***.
    - This proportion improved from October/15 (43%) and Q1/16 to Q4/16 (52% to 62%).
- About six in ten respondents rated QEC as having good or excellent ***value for its services***.
    - This proportion improved significantly from October/15 (55%) and Q1/16 to Q4/16 (59% to 67%).
- About six in ten respondents agreed that QEC is ***easy to do business with***.
    - This proportion improved greatly from Q1/16 to Q4/16 (56% to 68%), as well as the proportion who 'strongly' agreed (26% to 34%).

Satisfaction with Experience

- Nearly two-thirds (63%) of respondents were satisfied overall with their experience with QEC.
    - This proportion improved significantly from October/15 (57%) and Q1/16 to Q4/16 (57% to 69%).
- Reasons for satisfaction with QEC experience were related to:
    - Service (i.e., good customer service).

  - Outages (i.e., reliable energy supply/power outages are infrequent, quick outage response).
  - Good service overall.
- Reasons for dissatisfaction with QEC experience were related to:
  - *Billing* (i.e., inaccurate billing, billing is slow).
  - *Rates/charges* (i.e., energy costs are too high).
  - *Call centre* (.i.e., difficult to reach a live agent).
  - *Outages* (i.e., unreliable service/frequent outages).

Customer Service

- 58% of respondents have contacted QEC for customer at some point. Half of these contacts occurred more than six months from the interview date.
- About two-thirds of respondents were satisfied with QEC's customer service.
  - This proportion improved significantly from Q1/16 to Q4/16 (59% to 71%).

Billing

- Billing issues were primarily related to:
  - **Charges/payments** (i.e., overcharging/inaccurate billing amounts/billing not up to date, slow/unprocessed/unreceived payments).

- **Account** (i.e., could not update billing address/account information).

- This proportion improved significantly from October/15 to Q4/16 (63% to 75%).
- Seven in ten respondents were satisfied with the ***overall ease of understanding their bills***.
- Two-thirds of respondents were satisfied with the ***level of detail of bills***.

10.4 URRC REPORT 2012-01 2010/11 Phase II GRA

10.4.1 COST FUNCTIONALIZATION

URRC Findings: The URRC directs that, for purposes of cost functionalization, all cost items requiring allocation between the generation, distribution and general functions be supported by objective analysis at the time of the next COS Study. For the purposes of this Report, the URRC accepts the QEC proposed functionalization of costs.

QEC`s Response:

The Corporation incorporated this recommendation into the filing of this Application. The Corporation developed functionalization of costs in this COS study based on the Federal Energy Regulatory Commission (FERC) codes and analysis of expenses with operations staff. Where the existing systems did not break down the costs to the level needed for a COS study, the Corporation consulted with its operations staff to develop estimates of the proportion of expenses spent on generation and distribution related activities. Timesheet based analysis is not feasible due to the unavailability of such data. However, the

Corporation's estimates are based on its operational staff's experience and expectations. The Corporation believes the estimates are reasonable and can be relied upon for ratemaking purposes.

10.4.2 CLASSIFICATION STUDIES FOR POLES AND FIXTURES, OVERHEAD CONDUCTORS, UNDERGROUND CONDUITS, AND LINE TRANSFORMERS

URRC Findings: The URRC directs QEC to include QEC specific classification studies for poles and fixtures, overhead conductors, underground conduits, and line transformers at the time of the next COS Study. Further, when this change is implemented, the remaining general category of costs should be classified on the basis of all other costs that have been classified previously.

QEC's Response:

In the current Cost of Service analysis, the classification of these assets was completed based on Northwest Territories Power Corporations' (NTPC) treatment of these assets in their 2016/19 rate application. In the Corporation's view, QEC's distribution system is comparable to those of NTPC.

Considering the significant data and staff capacity requirements of a classification study, the Corporation considered the costs of undertaking this work relative to the benefits of the study. The analysis of the COS rate impact of updating the classification factors for these groups of assets suggests very small change in the revenue allocation between the rate classes. For example, changing the classification factors for all the above assets by 5% points (i.e., poles & fixtures 50% demand and 50% customer compared to proposed

45% demand and 55% customer, etc.) changes the cost allocation between customer classes by only about 0.2%. Based on this consideration, the Corporation determined that it was not cost effective to conduct QEC specific classification studies for poles and fixtures, overhead conductors, underground conduits, and line transformers.

10.4.3 CLASSIFICATION OF COSTS

URRC Findings: The URRC directs QEC to classify meter reading, billing and customer accounting to the customer category (or weighted customer category as may be appropriate) at the time of the next COS Study.

QEC's Response:

Classification of meter reading, billing and customer accounting in this Application is done in accordance with this recommendation.

10.4.4 ASSIGN NON-ELECTRIC REVENUES

URRC Findings: The URRC directs QEC to direct assign as revenue offsets, those components of non-electric revenues that have corresponding expenses included in revenue requirement and to allocate the remaining non-electric revenues on a revenue basis.

QEC's Response:

Non-electric revenues that have corresponding expenses included in revenue requirement (government contribution towards apprentice salaries and housing recoveries from employees) were credited as an offset to related expense categories (salaries & wages; supplies & services). The remaining other revenue was allocated on a revenue basis in accordance with this recommendation.

10.4.5 CUSTOMER WEIGHTING FACTORS

URRC Findings: The URRC directs QEC to conduct a study of the appropriate customer weighting factors for domestic, commercial, street and yard lighting customers at the time of the next COS Study.

QEC's Response:

The Corporation completed a review of customer weighting factors and updated the information in the COS Study.

10.4.6 NUNAVUT WIDE RATE REBALANCING

URRC Findings: Accordingly, for the purpose of future rate rebalancing applications URRC directs QEC as follows:

- **The Nunavut wide rates should be phased in having regard to rate stability considerations including impacts on subsidy levels. The maximum increase in rates in any year due to the Phase in of Nunavut wide rates should not exceed 5%.**
- **The phase-in changes should be applied for only at the time QEC applies for future GRAs.**

QEC's Response:

QEC's response to this recommendation is provided in Chapter 8 of this Application.

10.4.7 GOVERNMENT AND NON-GOVERNMENT CUSTOMER TYPE

URRC Findings: The URRC directs QEC to bring forward a proposal for elimination of Government / non-Government distinctions at the time of the next GRA.

QEC's Response:

The Corporation has eliminated the distinction between government and non-government classes in the COS study. Proposed rate adjustments target the same average cost for both government and non-government customers. Rate adjustments for the historic government rate classes are subject to the same adjustment constraints as for the non-government rate classes. The Corporation will revisit this issue in future rate applications.

10.4.8 RATE STRUCTURES FOR DOMESTIC, COMMERCIAL AND LIGHTING CUSTOMERS

URRC Findings: The URRC directs QEC to examine the rate structures for domestic, commercial and lighting customers at the time of the next Phase II GRA in light of the corresponding costs by rate component.

QEC's Response:

The Corporation's response to this recommendation is provided in Chapter 8 of this Application.

10.4.9 DEMAND METERS AND FIXED MINIMUM CHARGE BASED ON 5KW DEMAND

URRC Findings: The URRC is concerned that there are commercial customers without installed demand meters. There is also a concern that the fixed minimum

charge based on 5kW demand may not be an appropriate minimum charge for customers without demand meters. URRC directs QEC to address these concerns at the time of the next GRA.

QEC's Response:

The Corporation installs demand meters where it is operationally feasible. Advance commitment to install meters to customers in every community is not practical due to logistical challenges of operating in the northern isolated communities.

10.4.10 LEVELIZED MONTHLY CUSTOMER PAYMENT PLAN

URRC Findings: The URRC directs QEC to assess the benefits and costs of implementing a levelized monthly customer payment plan and to bring it forward at the time of QEC's next GRA. The URRC directs QEC to include a review of the appropriate frequency of meter reading true-ups for customers so that it achieves the maximum benefit for both QEC and its customers.

QEC's Response:

The Corporation is in the process of implementing a levelized monthly customer payment plan.

10.4.11 FEES AND SERVICE CHARGES INCLUDED IN SCHEDULE C

URRC Findings: The URRC directs QEC to provide the cost basis for QEC's proposed fees and service charges included in Schedule C based on QEC's unique circumstances, at the time of the next GRA.

QEC's Response:

A comparison of the existing service fees comparison with estimated average costs based on average hourly wages in provided in Table 10.3. The table shows that estimated average costs of the service are higher than the existing fees, excluding the internal meter accuracy test handling fee, which is not considered routine work. QEC is not proposing to change the existing service fees as per Schedule C of the terms and conditions of service.

Table 10.3:
2014/15 Comparison of Service Fees per Schedule C of Terms and Conditions of Service to Cost Estimates

Service Fees per Schedule C of QEC's T&C	Existing Fee	Estimated Average Effort	Estimated Average Cost	Notes
	($)	(Hour)	($)	
Residential Service Connection Fee	$20.0	1	$42.9	Requires Plant Operator
Commercial Service Connection Fee	$40.0	1	$42.9	Requires Plant Operator
Temporary Service Connection Fee	$40.0	1	$42.9	Requires Plant Operator
Seasonal Service Connection Fee	$40.0	1	$42.9	Requires Plant Operator
Reconnection Fee	$40.0	1	$42.9	Requires Plant Operator
Administration Fee for Initiating Disconnection Action	$25.0	1	$32.4	Requires Finance, Cust Service input
Administration Fee for Commencing Collection Action	$25.0	1	$32.4	Requires Finance, Cust Service input
Dishonored Payments Charge	$20.0	0.75	$25.6	Requires Billing Clerk
Service Call Response Fee	$40 or TMI			Minimum 1 hour of Plant Operator's input
Internal Meter Accuracy Test Handling Fee (Accurate meters only)	$150.0	3	$128.7	Requires Plant Operator
Private Area Lighting Maintenance Fees	TMI			
Service Extension Charges	TMI			
Overhead to Underground Conversion	TMI			
Relocation of Facilities	TMI			

Average hourly wages

	Plant Operator	Billing Clerk	Customer service Rep.
Average Hourly Wage ($/hr)	$42.9	$34.1	$30.7

10.4.12 DEMAND CONSERVATION INITIATIVES

URRC Findings: The URRC encourages QEC to bring forward any DSM and conservation initiative that have rates and rate design implications for review and approval by the responsible Minister on a timely basis as and when they are ready for implementation without necessarily waiting for the next GRA. URRC directs that updates with respect to DSM and conservation initiatives should be provided at the time of the next GRA.

The Corporation filed a net metering application with the Minister in 2017. The Corporation will bring forward any other initiatives in this regard, if and when such initiatives arise, consistent with this recommendation.

10.4.13 SUBSIDY PROGRAM

URRC Findings: The URRC directs that any changes with respect to the subsidy program be addressed at the time of the next GRA.

The Corporation has provided a discussion of how its rate proposals may interact with the subsidy program in Chapter 8. In practice, any changes to the subsidy program are administered by the Government of Nunavut.

APPENDIX A

SUMMARY OF GENERATION SALES AND REVENUE

Schedule A-1

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

500 Total of Kitikmeot Area

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	11,127	11,144	11,200	11,347	11,626	11,773
2	Customers	1,872	1,789	1,834	1,860	1,891	1,922
3	Av. MWh Sales/Cust.	5.94	6.23	6.11	6.10	6.15	6.12
4	Revenue (000s)	10,685	10,330	10,491	10,748	11,173	11,326
5	Cents/kWh	96.03	92.70	93.67	94.72	96.10	96.20
	Commercial						
6	Sales (MWh)	14,613	15,275	16,979	17,415	17,717	17,817
7	Customers	635	596	611	637	642	647
8	Av. MWh Sales/Cust.	23.01	25.63	27.79	27.35	27.60	27.54
9	Revenue (000s)	12,339	12,836	13,965	14,525	14,578	14,670
10	Cents /kWh	84.44	84.03	82.25	83.40	82.28	82.34
	Streetlights						
11	Sales (MWh)	349	349	349	352	352	352
12	Revenue (000s)	331	326	332	319	332	332
13	Cents /kWh	94.79	93.32	95.05	90.45	94.29	94.29
	Total						
14	**Sales (MWh)**	**26,088**	**26,767**	**28,528**	**29,115**	**29,696**	**29,943**
15	Customers	2,507	*2,385*	2,445	2,497	2,533	2,569
16	Revenue (000s)	23,354	23,491	24,788	25,591	26,084	26,328
17	Cents /kWh	89.52	87.76	86.89	87.90	87.84	87.93
	GENERATION (MWh)						
18	**Total Station Service**	**579**	**605**	**549**	**562**	**614**	**611**
19	**Station Service - % of Gen.**	2.0%	2.1%	1.8%	1.8%	1.9%	1.9%
20	**Total Losses**	**1,624**	**1,671**	**1,532**	**1,669**	**1,700**	**1,686**
21	**Losses - % of Gen.**	5.7%	5.8%	5.0%	5.3%	5.3%	5.2%
22	**Total Generation**	**28,291**	**29,044**	**30,609**	**31,346**	**32,010**	**32,240**
	Source						
23	Diesel Generation (MWh)	28,291	29,044	30,609	31,346	32,010	32,240
24	Diesel Efficiency (KWh/L)	3.68	3.61	3.66	3.66	3.66	3.66
25	Liters (000s)	7,685	8,039	8,362	8,571	8,752	8,815
	Peak						
26	Peak Load (KW)	5,342	5,592	5,574	5,860	6,004	5,988
27	Load Factor	60%	59%	63%	61%	61%	61%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.1

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

501 Cambridge Bay

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	3,546	3,538	3,553	3,555	3,658	3,670
2	Customers	604	591	610	618	625	632
3	Av. MWh Sales/Cust.	5.87	5.99	5.82	5.75	5.85	5.81
4	Revenue (000s)	2,828	2,770	2,821	2,837	2,918	2,928
5	Cents/kWh	79.74	78.30	79.40	79.80	79.75	79.78
	Commercial						
6	Sales (MWh)	5,966	6,509	8,010	8,458	8,595	8,595
7	Customers	239	233	244	263	265	266
8	Av. MWh Sales/Cust.	24.96	27.93	32.83	32.14	32.48	32.31
9	Revenue (000s)	4,139	4,675	5,554	5,872	5,941	5,942
10	Cents /kWh	69.38	71.83	69.34	69.43	69.13	69.13
	Streetlights						
11	Sales (MWh)	119	119	119	123	123	123
12	Revenue (000s)	89	88	90	91	91	91
13	Cents /kWh	74.65	73.38	75.39	73.81	73.81	73.81
	Total						
14	**Sales (MWh)**	**9,631**	**10,166**	**11,683**	**12,136**	**12,376**	**12,388**
15	Customers	843	*824*	854	881	890	898
16	Revenue (000s)	7,056	7,533	8,465	8,800	8,950	8,961
17	Cents /kWh	73.26	74.10	72.46	72.51	72.31	72.33
	GENERATION (MWh)						
18	**Total Station Service**	156	132	144	170	173	170
19	**Station Service - % of Gen.**	1.5%	1.2%	1.2%	1.3%	1.3%	1.3%
20	**Losses**	480	797	532	570	655	670
21	**Losses - % of Gen.**	4.7%	7.2%	4.3%	4.4%	5.0%	5.1%
22	**Total Generation**	**10,267**	**11,095**	**12,359**	**12,876**	**13,204**	**13,228**
	Source						
23	Diesel Generation (MWh)	10,267	11,095	12,359	12,876	13,204	13,228
24	Diesel Efficiency (KWh/L)	3.69	3.67	3.70	3.68	3.68	3.68
25	Liters (000s)	2,782	3,024	3,338	3,499	3,588	3,595
	Peak						
26	Peak Load (KW)	1,839	2,091	2,178	2,265	2,347	2,343
27	Load Factor	64%	61%	65%	65%	64%	64%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.2

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

502 Gjoa Haven

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,148	2,190	2,230	2,223	2,271	2,333
2	Customers	337	318	322	320	328	337
3	Av. MWh Sales/Cust.	6.37	6.89	6.92	6.95	6.92	6.93
4	Revenue (000s)	2,039	2,008	2,057	2,053	2,151	2,210
5	Cents/kWh	94.90	91.69	92.28	92.37	94.71	94.70
	Commercial						
6	Sales (MWh)	2,829	2,761	2,923	3,092	3,024	3,115
7	Customers	107	98	97	101	102	103
8	Av. MWh Sales/Cust.	26.44	28.17	30.13	30.74	29.68	30.18
9	Revenue (000s)	2,540	2,429	2,549	2,920	2,715	2,794
10	Cents /kWh	89.78	87.97	87.23	94.46	89.79	89.69
	Streetlights						
11	Sales (MWh)	77	77	77	77	77	77
12	Revenue (000s)	73	72	73	73	73	73
13	Cents /kWh	96.02	94.18	96.02	96.02	96.02	96.02
	Total						
14	**Sales (MWh)**	**5,053**	**5,027**	**5,229**	**5,391**	**5,371**	**5,525**
15	Customers	444	*416*	419	421	430	440
16	Revenue (000s)	4,652	4,509	4,680	5,047	4,939	5,077
17	Cents /kWh	92.05	89.68	89.51	93.62	91.96	91.90
	GENERATION (MWh)						
18	**Total Station Service**	119	89	98	104	104	103
19	**Station Service - % of Gen.**	2.1%	1.6%	1.7%	1.8%	1.8%	1.7%
20	**Losses**	420	308	293	355	338	326
21	**Losses - % of Gen.**	7.5%	5.7%	5.2%	6.1%	5.8%	5.5%
22	**Total Generation**	**5,593**	**5,424**	**5,619**	**5,851**	**5,813**	**5,953**
	Source						
23	Diesel Generation (MWh)	5,593	5,424	5,619	5,851	5,813	5,953
24	Diesel Efficiency (KWh/L)	3.73	3.67	3.69	3.65	3.65	3.65
25	Liters (000s)	1,499	1,478	1,521	1,603	1,593	1,631
	Peak						
26	Peak Load (KW)	984	940	960	1,100	1,061	1,067
27	Load Factor	65%	66%	67%	61%	63%	64%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.3

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

503 Taloyoak

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,533	1,565	1,573	1,654	1,682	1,718
2	Customers	255	244	249	258	263	270
3	Av. MWh Sales/Cust.	6.01	6.42	6.32	6.42	6.39	6.37
4	Revenue (000s)	1,664	1,581	1,593	1,704	1,821	1,861
5	Cents/kWh	108.54	101.00	101.30	103.07	108.28	108.29
	Commercial						
6	Sales (MWh)	1,818	1,917	2,005	1,824	1,923	1,942
7	Customers	95	81	82	81	82	82
8	Av. MWh Sales/Cust.	19.13	23.67	24.46	22.63	23.59	23.56
9	Revenue (000s)	1,830	1,885	2,017	1,836	1,937	1,957
10	Cents /kWh	100.70	98.32	100.60	100.68	100.75	100.73
	Streetlights						
11	Sales (MWh)	56	56	56	56	56	56
12	Revenue (000s)	61	59	61	47	61	61
13	Cents /kWh	107.94	105.62	107.93	83.81	107.94	107.94
	Total						
14	**Sales (MWh)**	**3,407**	**3,539**	**3,635**	**3,533**	**3,661**	**3,717**
15	Customers	350	*325*	331	338	345	352
16	Revenue (000s)	3,555	3,525	3,671	3,588	3,819	3,878
17	Cents /kWh	104.35	99.62	101.01	101.53	104.32	104.33
	GENERATION (MWh)						
18	**Total Station Service**	91	79	88	92	94	93
19	**Station Service - % of Gen.**	2.5%	2.1%	2.2%	2.4%	2.4%	2.3%
20	**Losses**	101	199	241	297	234	241
21	**Losses - % of Gen.**	2.8%	5.2%	6.1%	7.6%	5.9%	5.9%
22	**Total Generation**	**3,599**	**3,817**	**3,964**	**3,923**	**3,989**	**4,051**
	Source						
23	Diesel Generation (MWh)	3,599	3,817	3,964	3,923	3,989	4,051
24	Diesel Efficiency (KWh/L)	3.58	3.46	3.51	3.59	3.59	3.59
25	Liters (000s)	1,005	1,104	1,129	1,093	1,111	1,128
	Peak						
26	Peak Load (KW)	748	760	730	730	768	775
27	Load Factor	55%	57%	62%	61%	59%	60%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.4

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

504 Kugaaruk

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,373	1,344	1,386	1,407	1,451	1,484
2	Customers	199	186	187	195	199	203
3	Av. MWh Sales/Cust.	6.90	7.23	7.41	7.21	7.28	7.30
4	Revenue (000s)	1,611	1,562	1,609	1,693	1,699	1,738
5	Cents/kWh	117.29	116.20	116.09	120.35	117.13	117.12
	Commercial						
6	Sales (MWh)	1,264	1,143	1,123	1,215	1,227	1,236
7	Customers	68	59	59	63	64	65
8	Av. MWh Sales/Cust.	18.59	19.38	19.04	19.21	19.21	19.15
9	Revenue (000s)	1,335	1,201	1,192	1,322	1,300	1,310
10	Cents /kWh	105.59	105.05	106.10	108.82	105.92	105.92
	Streetlights						
11	Sales (MWh)	31	31	31	31	31	31
12	Revenue (000s)	30	30	30	30	30	30
13	Cents /kWh	96.29	95.43	96.28	96.28	96.29	96.29
	Total						
14	**Sales (MWh)**	**2,669**	**2,519**	**2,541**	**2,653**	**2,709**	**2,752**
15	Customers	267	*245*	246	258	263	268
16	Revenue (000s)	2,976	2,793	2,831	3,045	3,029	3,078
17	Cents /kWh	111.50	110.88	111.43	114.79	111.81	111.85
	GENERATION (MWh)						
18	**Total Station Service**	74	69	74	69	76	77
19	**Station Service - % of Gen.**	2.5%	2.5%	2.6%	2.4%	2.6%	2.5%
20	**Losses**	225	213	214	178	204	200
21	**Losses - % of Gen.**	7.6%	7.6%	7.6%	6.2%	6.8%	6.6%
22	**Total Generation**	**2,967**	**2,801**	**2,829**	**2,900**	**2,990**	**3,029**
	Source						
23	Diesel Generation (MWh)	2,967	2,801	2,829	2,900	2,990	3,029
24	Diesel Efficiency (KWh/L)	3.98	3.60	3.75	3.72	3.72	3.72
25	Liters (000s)	746	778	755	780	804	814
	Peak						
26	Peak Load (KW)	665	734	669	688	719	710
27	Load Factor	51%	44%	48%	48%	47%	49%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-1.5

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

505 Kugluktuk

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,525	2,505	2,458	2,508	2,564	2,568
2	Customers	477	450	466	469	475	481
3	Av. MWh Sales/Cust.	5.29	5.57	5.28	5.34	5.40	5.34
4	Revenue (000s)	2,543	2,408	2,410	2,460	2,584	2,589
5	Cents/kWh	100.70	96.10	98.02	98.06	100.79	100.84
	Commercial						
6	Sales (MWh)	2,736	2,945	2,917	2,827	2,948	2,928
7	Customers	126	125	129	129	130	131
8	Av. MWh Sales/Cust.	21.72	23.56	22.61	21.89	22.69	22.40
9	Revenue (000s)	2,495	2,646	2,652	2,574	2,685	2,668
10	Cents /kWh	91.17	89.86	90.93	91.06	91.07	91.11
	Streetlights						
11	Sales (MWh)	66	66	66	66	66	66
12	Revenue (000s)	77	77	77	77	77	77
13	Cents /kWh	118.12	117.14	118.12	118.12	118.12	118.12
	Total						
14	**Sales (MWh)**	**5,327**	**5,516**	**5,441**	**5,401**	**5,578**	**5,562**
15	Customers	603	*575*	595	599	605	612
16	Revenue (000s)	5,115	5,131	5,139	5,112	5,347	5,335
17	Cents /kWh	96.02	93.02	94.46	94.64	95.86	95.92
	GENERATION (MWh)						
18	**Total Station Service**	140	236	146	126	167	169
19	**Station Service - % of Gen.**	2.4%	4.0%	2.5%	2.2%	2.8%	2.8%
20	**Losses**	398	154	253	268	268	249
21	**Losses - % of Gen.**	6.8%	2.6%	4.3%	4.6%	4.5%	4.2%
22	**Total Generation**	**5,865**	**5,906**	**5,839**	**5,796**	**6,013**	**5,980**
	Source						
23	Diesel Generation (MWh)	5,865	5,906	5,839	5,796	6,013	5,980
24	Diesel Efficiency (KWh/L)	3.55	3.57	3.61	3.63	3.63	3.63
25	Liters (000s)	1,652	1,656	1,620	1,597	1,657	1,647
	Peak						
26	Peak Load (KW)	1,106	1,067	1,037	1,077	1,110	1,093
27	Load Factor	61%	63%	64%	61%	62%	62%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

600 Total of Kivalliq Area

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	17,301	17,149	17,078	17,356	17,867	17,920
2	Customers	2,960	2,823	2,948	2,993	3,033	3,074
3	Av. MWh Sales/Cust.	5.84	6.07	5.79	5.80	5.89	5.83
4	Revenue (000s)	13,873	13,255	13,422	13,713	14,354	14,418
5	Cents/kWh	80.18	77.29	78.59	79.01	80.34	80.46
	Commercial						
6	Sales (MWh)	25,511	26,045	26,627	26,680	26,852	26,969
7	Customers	817	799	823	820	826	831
8	Av. MWh Sales/Cust.	31.23	32.60	32.35	32.53	32.52	32.45
9	Revenue (000s)	18,675	18,828	19,359	19,271	19,748	19,814
10	Cents /kWh	73.20	72.29	72.71	72.23	73.55	73.47
	Streetlights						
11	Sales (MWh)	490	490	490	490	490	490
12	Revenue (000s)	450	445	450	451	450	450
13	Cents /kWh	92.02	90.86	91.92	92.15	92.02	92.02
	Total						
14	**Sales (MWh)**	**43,302**	**43,683**	**44,195**	**44,525**	**45,209**	**45,379**
15	Customers	3,777	*3,622*	3,771	3,813	3,859	3,905
16	Revenue (000s)	32,998	32,527	33,231	33,435	34,553	34,682
17	Cents /kWh	76.20	74.46	75.19	75.09	76.43	76.43
	GENERATION (MWh)						
18	**Total Station Service**	**1,611**	**1,521**	**1,400**	**1,409**	**1,528**	**1,515**
19	**Station Service - % of Gen.**	3.4%	3.3%	3.0%	2.9%	3.1%	3.1%
20	**Total Losses**	**1,964**	**1,528**	**1,651**	**1,949**	**1,916**	**1,767**
21	**Losses - % of Gen.**	4.2%	3.3%	3.5%	4.1%	3.9%	3.6%
22	**Total Generation**	**46,876**	**46,732**	**47,245**	**47,884**	**48,652**	**48,661**
	Source						
23	Diesel Generation (MWh)	46,876	46,732	47,245	47,884	48,652	48,661
24	Diesel Efficiency (KWh/L)	3.74	3.61	3.72	3.71	3.71	3.71
25	Liters (000s)	12,532	12,929	12,705	12,910	13,121	13,124
	Peak						
26	Peak Load (KW)	8,900	9,351	9,072	9,349	9,420	9,463
27	Load Factor	60%	57%	59%	58%	59%	59%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.1

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

601 Rankin Inlet

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	5,431	5,610	5,519	5,395	5,608	5,568
2	Customers	920	915	933	942	947	951
3	Av. MWh Sales/Cust.	5.90	6.13	5.92	5.73	5.92	5.86
4	Revenue (000s)	3,578	3,643	3,626	3,562	3,694	3,671
5	Cents/kWh	65.89	64.93	65.70	66.03	65.88	65.92
	Commercial						
6	Sales (MWh)	10,578	10,766	11,271	11,524	11,208	11,295
7	Customers	240	246	257	251	252	253
8	Av. MWh Sales/Cust.	44.07	43.77	43.86	45.85	44.49	44.73
9	Revenue (000s)	6,509	6,462	6,913	7,029	6,876	6,927
10	Cents /kWh	61.54	60.02	61.33	60.99	61.35	61.33
	Streetlights						
11	Sales (MWh)	142	142	142	142	142	142
12	Revenue (000s)	108	107	108	109	108	108
13	Cents /kWh	75.98	74.87	75.97	76.43	75.98	75.98
	Total						
14	**Sales (MWh)**	**16,151**	**16,519**	**16,933**	**17,061**	**16,959**	**17,006**
15	Customers	1,160	*1,161*	1,190	1,194	1,199	1,204
16	Revenue (000s)	10,196	10,212	10,647	10,700	10,679	10,706
17	Cents /kWh	63.13	61.82	62.88	62.72	62.97	62.95
	GENERATION (MWh)						
18	**Total Station Service**	643	620	534	581	625	618
19	**Station Service - % of Gen.**	3.7%	3.5%	3.0%	3.1%	3.4%	3.4%
20	**Losses**	830	638	646	848	796	757
21	**Losses - % of Gen.**	4.7%	3.6%	3.6%	4.6%	4.3%	4.1%
22	**Total Generation**	**17,625**	**17,777**	**18,113**	**18,490**	**18,379**	**18,382**
	Source						
23	Diesel Generation (MWh)	17,625	17,777	18,113	18,490	18,379	18,382
24	Diesel Efficiency (KWh/L)	3.77	3.73	3.75	3.77	3.77	3.77
25	Liters (000s)	4,675	4,760	4,827	4,905	4,875	4,876
	Peak						
26	Peak Load (KW)	3,189	3,130	3,182	3,348	3,284	3,278
27	Load Factor	63%	65%	65%	63%	64%	64%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.2

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

602 Baker Lake

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	3,973	3,791	3,699	3,764	3,834	3,819
2	Customers	672	639	655	662	666	670
3	Av. MWh Sales/Cust.	5.91	5.93	5.65	5.69	5.76	5.70
4	Revenue (000s)	2,939	2,764	2,749	2,806	2,840	2,830
5	Cents/kWh	73.96	72.91	74.31	74.55	74.06	74.10
	Commercial						
6	Sales (MWh)	4,714	4,624	4,391	4,318	4,362	4,337
7	Customers	185	178	177	172	172	173
8	Av. MWh Sales/Cust.	25.48	25.98	24.81	25.13	25.31	25.08
9	Revenue (000s)	3,280	3,230	3,160	2,930	3,151	3,135
10	Cents /kWh	69.58	69.86	71.96	67.86	72.23	72.27
	Streetlights						
11	Sales (MWh)	111	111	111	111	111	111
12	Revenue (000s)	84	83	84	84	84	84
13	Cents /kWh	75.47	74.95	75.23	75.46	75.47	75.47
	Total						
14	**Sales (MWh)**	**8,799**	**8,526**	**8,202**	**8,193**	**8,308**	**8,268**
15	Customers	857	*817*	832	834	839	843
16	Revenue (000s)	6,303	6,077	5,993	5,820	6,075	6,049
17	Cents /kWh	71.63	71.28	73.07	71.03	73.12	73.16
	GENERATION (MWh)						
18	**Total Station Service**	253	248	229	226	240	235
19	**Station Service - % of Gen.**	2.7%	2.7%	2.6%	2.5%	2.7%	2.6%
20	**Losses**	466	401	486	487	433	396
21	**Losses - % of Gen.**	4.9%	4.4%	5.5%	5.5%	4.8%	4.4%
22	**Total Generation**	**9,518**	**9,176**	**8,917**	**8,906**	**8,980**	**8,898**
	Source						
23	Diesel Generation (MWh)	9,518	9,176	8,917	8,906	8,980	8,898
24	Diesel Efficiency (KWh/L)	3.86	3.84	3.90	3.82	3.82	3.82
25	Liters (000s)	2,466	2,391	2,289	2,331	2,351	2,329
	Peak						
26	Peak Load (KW)	1,863	2,188	1,984	1,967	1,976	1,981
27	Load Factor	58%	48%	51%	52%	52%	51%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.3

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

603 Arviat

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	3,564	3,407	3,514	3,730	3,820	3,884
2	Customers	627	583	634	654	671	688
3	Av. MWh Sales/Cust.	5.68	5.84	5.54	5.70	5.70	5.65
4	Revenue (000s)	2,956	2,774	2,913	3,100	3,168	3,222
5	Cents/kWh	82.94	81.43	82.91	83.12	82.93	82.96
	Commercial						
6	Sales (MWh)	4,421	4,446	4,580	4,462	4,854	4,852
7	Customers	139	127	132	142	144	146
8	Av. MWh Sales/Cust.	31.81	35.01	34.70	31.37	33.69	33.25
9	Revenue (000s)	3,475	3,421	3,530	3,472	3,790	3,789
10	Cents /kWh	78.61	76.95	77.06	77.80	78.09	78.11
	Streetlights						
11	Sales (MWh)	95	95	95	95	95	95
12	Revenue (000s)	74	73	74	74	74	74
13	Cents /kWh	78.22	77.47	78.23	78.23	78.22	78.22
	Total						
14	**Sales (MWh)**	**8,079**	**7,948**	**8,189**	**8,287**	**8,768**	**8,830**
15	Customers	766	*710*	766	796	815	834
16	Revenue (000s)	6,505	6,269	6,517	6,646	7,032	7,086
17	Cents /kWh	80.52	78.88	79.59	80.20	80.20	80.24
	GENERATION (MWh)						
18	**Total Station Service**	220	218	215	191	218	221
19	**Station Service - % of Gen.**	2.6%	2.6%	2.5%	2.2%	2.4%	2.4%
20	**Losses**	219	216	257	158	282	235
21	**Losses - % of Gen.**	2.6%	2.6%	3.0%	1.8%	3.0%	2.5%
22	**Total Generation**	**8,518**	**8,381**	**8,661**	**8,635**	**9,268**	**9,286**
	Source						
23	Diesel Generation (MWh)	8,518	8,381	8,661	8,635	9,268	9,286
24	Diesel Efficiency (KWh/L)	3.77	3.33	3.77	3.70	3.70	3.70
25	Liters (000s)	2,259	2,520	2,298	2,334	2,505	2,510
	Peak						
26	Peak Load (KW)	1,556	1,734	1,613	1,652	1,767	1,793
27	Load Factor	62%	55%	61%	60%	60%	59%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.4

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

604 Coral Harbour

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,407	1,409	1,424	1,458	1,482	1,495
2	Customers	266	248	261	262	266	270
3	Av. MWh Sales/Cust.	5.29	5.68	5.46	5.57	5.57	5.53
4	Revenue (000s)	1,390	1,374	1,400	1,435	1,460	1,474
5	Cents/kWh	98.74	97.54	98.36	98.46	98.54	98.57
	Commercial						
6	Sales (MWh)	1,764	1,852	1,872	1,782	1,858	1,866
7	Customers	84	80	80	81	81	82
8	Av. MWh Sales/Cust.	21.00	23.16	23.40	22.14	22.90	22.81
9	Revenue (000s)	1,608	1,665	1,669	1,604	1,688	1,695
10	Cents /kWh	91.14	89.87	89.16	90.01	90.83	90.83
	Streetlights						
11	Sales (MWh)	51	51	51	51	51	51
12	Revenue (000s)	67	66	67	67	67	67
13	Cents /kWh	130.91	128.85	130.92	130.92	130.91	130.91
	Total						
14	**Sales (MWh)**	**3,222**	**3,312**	**3,347**	**3,291**	**3,391**	**3,413**
15	Customers	350	*328*	341	342	347	352
16	Revenue (000s)	3,064	3,105	3,137	3,106	3,215	3,236
17	Cents /kWh	95.09	93.73	93.71	94.39	94.80	94.82
	GENERATION (MWh)						
18	**Total Station Service**	173	154	136	127	152	148
19	**Station Service - % of Gen.**	4.9%	4.3%	3.8%	3.6%	4.2%	4.1%
20	**Losses**	130	86	42	123	116	97
21	**Losses - % of Gen.**	3.7%	2.4%	1.2%	3.5%	3.2%	2.7%
22	**Total Generation**	**3,525**	**3,552**	**3,525**	**3,541**	**3,659**	**3,658**
	Source						
23	Diesel Generation (MWh)	3,525	3,552	3,525	3,541	3,659	3,658
24	Diesel Efficiency (KWh/L)	3.46	3.36	3.39	3.37	3.37	3.37
25	Liters (000s)	1,019	1,057	1,039	1,051	1,086	1,086
	Peak						
26	Peak Load (KW)	699	700	680	731	729	727
27	Load Factor	58%	58%	59%	55%	57%	57%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.5

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

605 Chesterfield Inlet

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	715	726	695	725	724	724
2	Customers	132	126	128	128	129	130
3	Av. MWh Sales/Cust.	5.41	5.76	5.43	5.68	5.62	5.58
4	Revenue (000s)	726	728	708	725	734	734
5	Cents/kWh	101.53	100.31	101.88	99.96	101.38	101.41
	Commercial						
6	Sales (MWh)	1,157	1,195	1,177	1,161	1,190	1,184
7	Customers	60	56	57	57	57	57
8	Av. MWh Sales/Cust.	19.28	21.33	20.65	20.37	20.79	20.60
9	Revenue (000s)	1,104	1,118	1,122	1,087	1,134	1,129
10	Cents /kWh	95.39	93.57	95.28	93.57	95.32	95.35
	Streetlights						
11	Sales (MWh)	26	26	26	26	26	26
12	Revenue (000s)	35	35	35	35	35	35
13	Cents /kWh	133.13	131.01	133.14	133.14	133.13	133.13
	Total						
14	**Sales (MWh)**	**1,898**	**1,947**	**1,898**	**1,913**	**1,940**	**1,934**
15	Customers	192	*182*	185	185	186	187
16	Revenue (000s)	1,864	1,881	1,865	1,846	1,903	1,898
17	Cents /kWh	98.22	96.59	98.22	96.54	98.10	98.13
	GENERATION (MWh)						
18	**Total Station Service**	106	73	76	73	81	79
19	**Station Service - % of Gen.**	5.1%	3.5%	3.7%	3.5%	3.9%	3.8%
20	**Losses**	71	56	95	80	78	73
21	**Losses - % of Gen.**	3.4%	2.7%	4.6%	3.9%	3.7%	3.5%
22	**Total Generation**	**2,074**	**2,077**	**2,070**	**2,066**	**2,099**	**2,086**
	Source						
23	Diesel Generation (MWh)	2,074	2,077	2,070	2,066	2,099	2,086
24	Diesel Efficiency (KWh/L)	3.46	3.31	3.43	3.53	3.53	3.53
25	Liters (000s)	600	628	604	585	595	591
	Peak						
26	Peak Load (KW)	386	389	389	400	395	397
27	Load Factor	61%	61%	61%	59%	61%	60%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.6

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

606 Whale Cove

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	720	687	710	712	758	762
2	Customers	131	110	118	124	126	129
3	Av. MWh Sales/Cust.	5.50	6.24	6.02	5.75	6.00	5.92
4	Revenue (000s)	970	648	690	697	1,012	1,018
5	Cents/kWh	134.80	94.40	97.19	97.89	133.54	133.58
	Commercial						
6	Sales (MWh)	990	1,068	932	955	1,007	975
7	Customers	49	48	51	50	51	51
8	Av. MWh Sales/Cust.	20.20	22.25	18.27	19.01	19.84	19.04
9	Revenue (000s)	1,205	1,313	1,149	1,191	1,242	1,205
10	Cents /kWh	121.68	122.94	123.27	124.64	123.40	123.59
	Streetlights						
11	Sales (MWh)	33	33	33	33	33	33
12	Revenue (000s)	48	47	48	48	48	48
13	Cents /kWh	143.48	141.28	143.10	143.47	143.48	143.48
	Total						
14	**Sales (MWh)**	**1,743**	**1,788**	**1,675**	**1,701**	**1,798**	**1,771**
15	Customers	180	*158*	169	174	177	180
16	Revenue (000s)	2,223	2,008	1,886	1,936	2,302	2,271
17	Cents /kWh	127.51	112.32	112.61	113.81	128.05	128.27
	GENERATION (MWh)						
18	**Total Station Service**	149	136	130	144	138	136
19	**Station Service - % of Gen.**	7.5%	6.9%	7.1%	7.4%	6.9%	7.0%
20	**Losses**	97	51	39	86	62	53
21	**Losses - % of Gen.**	4.9%	2.6%	2.1%	4.5%	3.1%	2.7%
22	**Total Generation**	**1,989**	**1,975**	**1,844**	**1,931**	**1,998**	**1,960**
	Source						
23	Diesel Generation (MWh)	1,989	1,975	1,844	1,931	1,998	1,960
24	Diesel Efficiency (KWh/L)	3.54	3.66	3.52	3.70	3.70	3.70
25	Liters (000s)	562	540	524	522	540	530
	Peak						
26	Peak Load (KW)	475	430	390	380	408	402
27	Load Factor	48%	52%	54%	58%	56%	56%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-2.7

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

607 Naujaat

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,491	1,520	1,518	1,572	1,642	1,667
2	Customers	212	202	219	222	229	236
3	Av. MWh Sales/Cust.	7.03	7.52	6.93	7.10	7.18	7.07
4	Revenue (000s)	1,314	1,323	1,336	1,387	1,446	1,469
5	Cents/kWh	88.14	87.08	88.01	88.24	88.07	88.12
	Commercial						
6	Sales (MWh)	1,888	2,093	2,403	2,477	2,373	2,459
7	Customers	60	64	69	67	68	69
8	Av. MWh Sales/Cust.	31.46	32.70	34.82	36.93	34.82	35.52
9	Revenue (000s)	1,494	1,619	1,817	1,959	1,867	1,933
10	Cents /kWh	79.16	77.33	75.62	79.08	78.69	78.59
	Streetlights						
11	Sales (MWh)	31	31	31	31	31	31
12	Revenue (000s)	35	34	34	35	35	35
13	Cents /kWh	113.04	111.51	112.72	113.05	113.04	113.04
	Total						
14	**Sales (MWh)**	**3,409**	**3,643**	**3,951**	**4,079**	**4,045**	**4,157**
15	Customers	272	*266*	288	289	297	305
16	Revenue (000s)	2,843	2,976	3,187	3,380	3,347	3,436
17	Cents /kWh	83.39	81.68	80.66	82.87	82.75	82.66
	GENERATION (MWh)						
18	**Total Station Service**	68	71	79	68	75	77
19	**Station Service - % of Gen.**	1.9%	1.9%	1.9%	1.6%	1.7%	1.7%
20	**Losses**	151	80	85	167	149	157
21	**Losses - % of Gen.**	4.2%	2.1%	2.1%	3.9%	3.5%	3.6%
22	**Total Generation**	**3,627**	**3,794**	**4,115**	**4,315**	**4,269**	**4,391**
	Source						
23	Diesel Generation (MWh)	3,627	3,794	4,115	4,315	4,269	4,391
24	Diesel Efficiency (KWh/L)	3.81	3.67	3.66	3.65	3.65	3.65
25	Liters (000s)	952	1,033	1,124	1,182	1,170	1,203
	Peak						
26	Peak Load (KW)	731	780	834	871	861	885
27	Load Factor	57%	56%	56%	57%	57%	57%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

700 Total of Qikiqtaaluk area

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	37,120	36,926	36,659	36,604	37,407	38,070
2	Customers	6,510	6,688	6,491	6,609	6,711	6,816
3	Av. MWh Sales/Cust.	5.70	5.52	5.65	5.54	5.57	5.59
4	Revenue (000s)	27,721	26,735	27,007	27,059	28,000	28,448
5	Cents/kWh	74.68	72.40	73.67	73.93	74.85	74.73
	Commercial						
6	Sales (MWh)	65,061	61,741	62,772	63,188	63,577	64,353
7	Customers	1,878	1,793	1,781	1,802	1,816	1,829
8	Av. MWh Sales/Cust.	34.64	34.43	35.25	35.06	35.02	35.19
9	Revenue (000s)	42,197	39,760	41,002	40,435	41,501	41,938
10	Cents /kWh	64.86	64.40	65.32	63.99	65.28	65.17
	Streetlights						
11	Sales (MWh)	1,099	1,099	1,099	1,098	1,107	1,107
12	Revenue (000s)	958	952	945	989	967	967
13	Cents /kWh	87.19	86.68	86.03	90.09	87.35	87.35
	Total						
14	**Sales (MWh)**	**103,280**	**99,766**	**100,530**	**100,889**	**102,091**	**103,529**
15	Customers	8,388	*8,481*	8,272	8,411	8,527	8,645
16	Revenue (000s)	70,875	67,447	68,954	68,484	70,468	71,353
17	Cents /kWh	68.62	67.61	68.59	67.88	69.02	68.92
	GENERATION (MWh)						
18	**Total Station Service**	**4,384**	**4,141**	**4,013**	**4,138**	**4,360**	**4,214**
19	**Station Service - % of Gen.**	3.9%	3.8%	3.7%	3.8%	3.9%	3.7%
20	**Total Losses**	**4,329**	**4,401**	**4,607**	**4,684**	**4,623**	**4,694**
21	**Losses - % of Gen.**	3.9%	4.1%	4.2%	4.3%	4.2%	4.2%
22	**Total Generation**	**111,993**	**108,308**	**109,151**	**109,711**	**111,074**	**112,437**
	Source						
23	Diesel Generation (MWh)	111,993	108,308	109,151	109,711	111,074	112,437
24	Diesel Efficiency (KWh/L)	3.71	3.78	3.78	3.80	3.80	3.80
25	Liters (000s)	30,204	28,654	28,912	28,849	29,212	29,557
	Peak						
26	Peak Load (KW)	20,972	20,062	19,885	19,638	20,326	20,500
27	Load Factor	61%	62%	63%	64%	62%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.1

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

701 Iqaluit

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	18,104	17,847	17,824	17,819	18,105	18,665
2	Customers	3,226	3,563	3,322	3,422	3,486	3,551
3	Av. MWh Sales/Cust.	5.61	5.01	5.37	5.21	5.19	5.26
4	Revenue (000s)	11,612	11,134	11,459	11,426	11,669	12,020
5	Cents/kWh	64.14	62.39	64.29	64.12	64.45	64.40
	Commercial						
6	Sales (MWh)	38,586	35,484	36,717	37,263	37,356	37,981
7	Customers	752	757	755	772	780	787
8	Av. MWh Sales/Cust.	51.31	46.87	48.63	48.25	47.92	48.27
9	Revenue (000s)	20,887	18,848	19,783	20,106	20,230	20,554
10	Cents /kWh	54.13	53.12	53.88	53.96	54.16	54.12
	Streetlights						
11	Sales (MWh)	411	411	411	411	419	419
12	Revenue (000s)	258	261	246	290	267	267
13	Cents /kWh	62.81	63.64	59.85	70.51	63.63	63.63
	Total						
14	**Sales (MWh)**	**57,101**	**53,741**	**54,951**	**55,492**	**55,880**	**57,065**
15	Customers	3,978	*4,320*	4,077	4,194	4,265	4,338
16	Revenue (000s)	32,757	30,244	31,488	31,821	32,166	32,841
17	Cents /kWh	57.37	56.28	57.30	57.34	57.56	57.55
	GENERATION (MWh)						
18	**Total Station Service**	2,418	2,202	2,188	2,247	2,464	2,326
19	**Station Service - % of Gen.**	4.0%	3.8%	3.7%	3.8%	4.1%	3.8%
20	**Losses**	1,222	1,863	2,001	1,906	1,875	2,066
21	**Losses - % of Gen.**	2.0%	3.2%	3.4%	3.2%	3.1%	3.4%
22	**Total Generation**	**60,741**	**57,807**	**59,140**	**59,646**	**60,219**	**61,456**
	Source						
23	Diesel Generation (MWh)	60,741	57,807	59,140	59,646	60,219	61,456
24	Diesel Efficiency (KWh/L)	3.82	3.97	3.96	3.96	3.96	3.96
25	Liters (000s)	15,901	14,573	14,934	15,062	15,207	15,519
	Peak						
26	Peak Load (KW)	10,518	9,813	9,738	9,707	10,096	10,259
27	Load Factor	66%	67%	69%	70%	68%	68%

Note: Revenues do not include fuel rider revenues/refunds.
1. Revenues do not include fuel rider revenues.
2. The actual losses for 2010/11 are low due to major billing error adjustments in Iqaluit.

Schedule A-3.2

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

702 Pangnirtung

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,545	2,558	2,508	2,468	2,552	2,547
2	Customers	480	467	475	476	480	484
3	Av. MWh Sales/Cust.	5.30	5.48	5.28	5.18	5.31	5.26
4	Revenue (000s)	1,854	1,785	1,753	1,736	1,860	1,858
5	Cents/kWh	72.84	69.79	69.90	70.33	72.91	72.96
	Commercial						
6	Sales (MWh)	3,551	3,318	3,365	3,355	3,315	3,341
7	Customers	129	119	120	117	118	118
8	Av. MWh Sales/Cust.	27.52	27.88	28.04	28.65	28.19	28.30
9	Revenue (000s)	2,324	2,150	2,222	2,193	2,185	2,201
10	Cents /kWh	65.46	64.80	66.03	65.37	65.90	65.88
	Streetlights						
11	Sales (MWh)	141	141	141	141	141	141
12	Revenue (000s)	102	100	102	102	102	102
13	Cents /kWh	72.13	70.66	72.14	72.14	72.13	72.13
	Total						
14	**Sales (MWh)**	**6,237**	**6,016**	**6,014**	**5,964**	**6,008**	**6,029**
15	Customers	609	*586*	595	593	598	602
16	Revenue (000s)	4,280	4,034	4,077	4,030	4,147	4,161
17	Cents /kWh	68.62	67.06	67.79	67.58	69.03	69.02
	GENERATION (MWh)						
18	**Total Station Service**	342	329	310	307	296	299
19	**Station Service - % of Gen.**	5.0%	5.1%	4.8%	4.8%	4.6%	4.6%
20	**Losses**	222	114	141	146	147	139
21	**Losses - % of Gen.**	3.3%	1.8%	2.2%	2.3%	2.3%	2.1%
22	**Total Generation**	**6,801**	**6,459**	**6,465**	**6,418**	**6,451**	**6,467**
	Source						
23	Diesel Generation (MWh)	6,801	6,459	6,465	6,418	6,451	6,467
24	Diesel Efficiency (KWh/L)	3.72	3.69	3.49	3.59	3.59	3.59
25	Liters (000s)	1,828	1,749	1,855	1,788	1,797	1,801
	Peak						
26	Peak Load (KW)	1,377	1,415	1,196	1,208	1,257	1,262
27	Load Factor	56%	52%	62%	61%	59%	58%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.3

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

703 Cape Dorset

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,365	2,229	2,182	2,186	2,232	2,248
2	Customers	433	411	413	413	419	424
3	Av. MWh Sales/Cust.	5.46	5.42	5.28	5.29	5.33	5.30
4	Revenue (000s)	1,769	1,605	1,595	1,587	1,675	1,687
5	Cents/kWh	74.83	72.02	73.11	72.62	75.02	75.04
	Commercial						
6	Sales (MWh)	3,601	3,418	2,969	2,784	3,068	2,968
7	Customers	136	118	118	118	118	119
8	Av. MWh Sales/Cust.	26.48	28.97	25.16	23.70	25.94	24.93
9	Revenue (000s)	2,627	2,491	2,179	2,028	2,242	2,173
10	Cents /kWh	72.96	72.87	73.40	72.84	73.09	73.23
	Streetlights						
11	Sales (MWh)	76	76	76	76	76	76
12	Revenue (000s)	78	77	78	78	78	78
13	Cents /kWh	103.27	102.38	103.28	103.17	103.27	103.27
	Total						
14	**Sales (MWh)**	**6,042**	**5,723**	**5,227**	**5,046**	**5,376**	**5,292**
15	Customers	569	*529*	531	531	537	543
16	Revenue (000s)	4,475	4,173	3,853	3,694	3,995	3,939
17	Cents /kWh	74.07	72.93	73.71	73.20	74.32	74.43
	GENERATION (MWh)						
18	**Total Station Service**	139	172	167	149	167	169
19	**Station Service - % of Gen.**	2.1%	2.8%	2.9%	2.7%	2.9%	3.0%
20	**Losses**	308	309	292	314	276	262
21	**Losses - % of Gen.**	4.7%	5.0%	5.1%	5.7%	4.8%	4.6%
22	**Total Generation**	**6,488**	**6,203**	**5,685**	**5,509**	**5,819**	**5,724**
	Source						
23	Diesel Generation (MWh)	6,488	6,203	5,685	5,509	5,819	5,724
24	Diesel Efficiency (KWh/L)	3.45	3.40	3.32	3.48	3.48	3.48
25	Liters (000s)	1,881	1,826	1,712	1,583	1,672	1,645
	Peak						
26	Peak Load (KW)	1,530	1,423	1,644	1,488	1,517	1,479
27	Load Factor	48%	50%	39%	42%	44%	44%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.4

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

704 Resolute Bay

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	734	694	606	570	614	589
2	Customers	116	97	96	95	95	94
3	Av. MWh Sales/Cust.	6.33	7.15	6.32	5.97	6.48	6.26
4	Revenue (000s)	776	716	634	598	649	623
5	Cents/kWh	105.65	103.19	104.63	104.95	105.66	105.78
	Commercial						
6	Sales (MWh)	3,257	3,550	3,272	3,265	3,154	3,162
7	Customers	131	122	112	107	106	106
8	Av. MWh Sales/Cust.	24.86	29.10	29.22	30.57	29.63	29.80
9	Revenue (000s)	3,272	3,495	3,374	3,175	3,258	3,265
10	Cents /kWh	100.46	98.46	103.11	97.23	103.28	103.26
	Streetlights						
11	Sales (MWh)	40	40	40	40	40	40
12	Revenue (000s)	57	56	57	57	57	57
13	Cents /kWh	142.22	139.96	142.22	142.22	142.22	142.22
	Total						
14	**Sales (MWh)**	**4,032**	**4,283**	**3,919**	**3,875**	**3,808**	**3,791**
15	Customers	247	*219*	208	202	201	200
16	Revenue (000s)	4,105	4,267	4,065	3,829	3,963	3,945
17	Cents /kWh	101.82	99.62	103.75	98.83	104.07	104.06
	GENERATION (MWh)						
18	**Total Station Service**	397	393	356	351	341	337
19	**Station Service - % of Gen.**	7.9%	7.7%	7.7%	7.7%	7.4%	7.5%
20	**Losses**	586	427	332	355	435	384
21	**Losses - % of Gen.**	11.7%	8.4%	7.2%	7.7%	9.5%	8.5%
22	**Total Generation**	**5,015**	**5,103**	**4,607**	**4,580**	**4,584**	**4,511**
	Source						
23	Diesel Generation (MWh)	5,015	5,103	4,607	4,580	4,584	4,511
24	Diesel Efficiency (KWh/L)	3.66	3.52	3.60	3.62	3.62	3.62
25	Liters (000s)	1,370	1,448	1,281	1,265	1,266	1,246
	Peak						
26	Peak Load (KW)	898	908	916	829	829	817
27	Load Factor	64%	64%	57%	63%	63%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.5

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

705 Pond Inlet

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,423	2,513	2,493	2,556	2,612	2,650
2	Customers	425	409	408	421	427	434
3	Av. MWh Sales/Cust.	5.70	6.15	6.11	6.08	6.11	6.10
4	Revenue (000s)	2,391	2,340	2,338	2,401	2,576	2,614
5	Cents/kWh	98.68	93.09	93.77	93.96	98.63	98.64
	Commercial						
6	Sales (MWh)	3,215	3,018	3,183	3,246	3,339	3,380
7	Customers	125	104	105	113	114	115
8	Av. MWh Sales/Cust.	25.72	29.02	30.32	28.79	29.38	29.49
9	Revenue (000s)	2,793	2,584	2,740	2,791	2,884	2,918
10	Cents /kWh	86.86	85.63	86.06	85.97	86.36	86.34
	Streetlights						
11	Sales (MWh)	113	113	113	113	113	113
12	Revenue (000s)	124	122	123	124	124	124
13	Cents /kWh	108.94	107.46	108.63	108.94	108.94	108.94
	Total						
14	**Sales (MWh)**	**5,752**	**5,645**	**5,790**	**5,915**	**6,065**	**6,144**
15	Customers	550	*513*	513	533	541	549
16	Revenue (000s)	5,307	5,046	5,200	5,316	5,584	5,656
17	Cents /kWh	92.28	89.39	89.82	89.87	92.07	92.06
	GENERATION (MWh)						
18	**Total Station Service**	267	229	236	232	256	252
19	**Station Service - % of Gen.**	4.3%	3.7%	3.7%	3.6%	3.8%	3.8%
20	**Losses**	226	298	330	255	336	317
21	**Losses - % of Gen.**	3.6%	4.8%	5.2%	4.0%	5.0%	4.7%
22	**Total Generation**	**6,244**	**6,172**	**6,355**	**6,402**	**6,656**	**6,713**
	Source						
23	Diesel Generation (MWh)	6,244	6,172	6,355	6,402	6,656	6,713
24	Diesel Efficiency (KWh/L)	3.56	3.70	3.69	3.68	3.68	3.68
25	Liters (000s)	1,754	1,668	1,722	1,740	1,809	1,824
	Peak						
26	Peak Load (KW)	1,235	1,196	1,205	1,168	1,269	1,285
27	Load Factor	58%	59%	60%	63%	60%	60%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.6

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

706 Igloolik

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	2,655	2,830	2,724	2,672	2,776	2,762
2	Customers	442	435	442	440	444	449
3	Av. MWh Sales/Cust.	6.01	6.51	6.16	6.07	6.25	6.16
4	Revenue (000s)	1,774	1,867	1,816	1,780	1,851	1,844
5	Cents/kWh	66.83	65.95	66.64	66.61	66.69	66.74
	Commercial						
6	Sales (MWh)	3,276	3,425	3,441	3,652	3,645	3,702
7	Customers	132	122	123	127	129	131
8	Av. MWh Sales/Cust.	24.82	28.08	27.98	28.68	28.24	28.30
9	Revenue (000s)	2,019	2,098	2,117	1,984	2,245	2,279
10	Cents /kWh	61.64	61.26	61.53	54.32	61.58	61.56
	Streetlights						
11	Sales (MWh)	96	96	96	95	95	95
12	Revenue (000s)	70	68	70	70	69	69
13	Cents /kWh	72.76	71.47	72.77	73.15	73.08	73.08
	Total						
14	**Sales (MWh)**	**6,026**	**6,351**	**6,261**	**6,419**	**6,516**	**6,559**
15	Customers	574	*557*	565	568	574	579
16	Revenue (000s)	3,863	4,033	4,002	3,833	4,165	4,192
17	Cents /kWh	64.10	63.50	63.93	59.71	63.93	63.91
	GENERATION (MWh)						
18	**Total Station Service**	153	116	115	115	135	127
19	**Station Service - % of Gen.**	2.4%	1.7%	1.7%	1.7%	2.0%	1.8%
20	**Losses**	239	141	211	236	239	224
21	**Losses - % of Gen.**	3.7%	2.1%	3.2%	3.5%	3.5%	3.2%
22	**Total Generation**	**6,419**	**6,608**	**6,587**	**6,771**	**6,891**	**6,910**
	Source						
23	Diesel Generation (MWh)	6,419	6,608	6,587	6,771	6,891	6,910
24	Diesel Efficiency (KWh/L)	3.49	3.66	3.68	3.75	3.75	3.75
25	Liters (000s)	1,839	1,805	1,791	1,806	1,838	1,843
	Peak						
26	Peak Load (KW)	1,294	1,302	1,209	1,247	1,328	1,326
27	Load Factor	57%	58%	62%	62%	59%	59%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.7

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

707 Hall Beach

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,408	1,362	1,362	1,347	1,383	1,411
2	Customers	210	189	193	190	194	199
3	Av. MWh Sales/Cust.	6.70	7.21	7.05	7.10	7.12	7.09
4	Revenue (000s)	1,336	1,222	1,256	1,357	1,312	1,338
5	Cents/kWh	94.93	89.68	92.26	100.75	94.80	94.82
	Commercial						
6	Sales (MWh)	1,652	1,573	1,629	1,632	1,601	1,643
7	Customers	70	65	64	63	64	64
8	Av. MWh Sales/Cust.	23.59	24.20	25.45	26.00	25.22	25.55
9	Revenue (000s)	1,477	1,421	1,568	1,338	1,545	1,581
10	Cents /kWh	89.40	90.36	96.26	82.02	96.46	96.22
	Streetlights						
11	Sales (MWh)	42	42	42	42	42	42
12	Revenue (000s)	45	44	45	45	45	45
13	Cents /kWh	107.47	106.56	107.48	107.48	107.47	107.47
	Total						
14	**Sales (MWh)**	**3,101**	**2,977**	**3,032**	**3,020**	**3,027**	**3,096**
15	Customers	280	*254*	257	252	258	263
16	Revenue (000s)	2,858	2,687	2,869	2,740	2,901	2,963
17	Cents /kWh	92.15	90.28	94.62	90.72	95.85	95.73
	GENERATION (MWh)						
18	**Total Station Service**	205	275	231	249	258	262
19	**Station Service - % of Gen.**	5.7%	8.3%	6.8%	7.4%	7.6%	7.6%
20	**Losses**	267	66	114	105	90	84
21	**Losses - % of Gen.**	7.5%	2.0%	3.4%	3.1%	2.7%	2.4%
22	**Total Generation**	**3,573**	**3,318**	**3,376**	**3,374**	**3,374**	**3,441**
	Source						
23	Diesel Generation (MWh)	3,573	3,318	3,376	3,374	3,374	3,441
24	Diesel Efficiency (KWh/L)	3.63	3.48	3.65	3.65	3.65	3.65
25	Liters (000s)	984	953	925	924	924	943
	Peak						
26	Peak Load (KW)	700	667	672	681	669	682
27	Load Factor	58%	57%	57%	57%	58%	58%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.8

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

708 Qikiqtarjuaq

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	947	1,020	990	996	1,040	1,043
2	Customers	194	190	192	198	201	203
3	Av. MWh Sales/Cust.	4.88	5.37	5.16	5.04	5.19	5.13
4	Revenue (000s)	860	835	830	826	945	948
5	Cents/kWh	90.74	81.95	83.84	82.95	90.86	90.91
	Commercial						
6	Sales (MWh)	1,419	1,493	1,574	1,416	1,518	1,528
7	Customers	85	79	79	80	81	81
8	Av. MWh Sales/Cust.	16.69	18.90	19.92	17.70	18.84	18.82
9	Revenue (000s)	1,252	1,296	1,404	1,154	1,326	1,334
10	Cents /kWh	88.28	86.80	89.22	81.48	87.34	87.33
	Streetlights						
11	Sales (MWh)	32	32	32	32	32	32
12	Revenue (000s)	38	38	38	38	38	38
13	Cents /kWh	119.36	117.37	119.02	119.35	119.36	119.36
	Total						
14	**Sales (MWh)**	**2,398**	**2,545**	**2,596**	**2,444**	**2,591**	**2,603**
15	Customers	279	*269*	271	278	281	285
16	Revenue (000s)	2,150	2,170	2,273	2,018	2,310	2,321
17	Cents /kWh	89.67	85.24	87.54	82.58	89.15	89.16
	GENERATION (MWh)						
18	**Total Station Service**	75	79	65	128	92	93
19	**Station Service - % of Gen.**	2.8%	2.8%	2.3%	4.6%	3.2%	3.2%
20	**Losses**	182	185	115	193	165	172
21	**Losses - % of Gen.**	6.9%	6.6%	4.1%	7.0%	5.8%	6.0%
22	**Total Generation**	**2,655**	**2,809**	**2,776**	**2,765**	**2,847**	**2,867**
	Source						
23	Diesel Generation (MWh)	2,655	2,809	2,776	2,765	2,847	2,867
24	Diesel Efficiency (KWh/L)	3.51	3.50	3.47	3.51	3.51	3.51
25	Liters (000s)	756	803	800	788	811	817
	Peak						
26	Peak Load (KW)	497	495	500	505	522	520
27	Load Factor	61%	65%	63%	62%	62%	63%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.9

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

709 Kimmirut

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	780	757	771	725	743	740
2	Customers	142	139	137	137	136	136
3	Av. MWh Sales/Cust.	5.49	5.45	5.63	5.30	5.46	5.46
4	Revenue (000s)	838	826	825	779	799	796
5	Cents/kWh	107.52	109.14	107.03	107.48	107.53	107.53
	Commercial						
6	Sales (MWh)	1,142	1,078	1,066	1,007	1,065	1,047
7	Customers	59	54	55	56	56	56
8	Av. MWh Sales/Cust.	19.36	19.96	19.39	18.06	19.14	18.86
9	Revenue (000s)	1,048	982	979	937	981	965
10	Cents /kWh	91.80	91.14	91.81	93.09	92.13	92.19
	Streetlights						
11	Sales (MWh)	33	33	33	33	33	33
12	Revenue (000s)	44	44	44	44	44	44
13	Cents /kWh	134.08	133.39	133.71	133.82	134.08	134.08
	Total						
14	**Sales (MWh)**	**1,955**	**1,868**	**1,870**	**1,765**	**1,841**	**1,820**
15	Customers	201	*193*	192	193	192	191
16	Revenue (000s)	1,931	1,853	1,848	1,761	1,824	1,806
17	Cents /kWh	98.78	99.18	98.83	99.76	99.10	99.19
	GENERATION (MWh)						
18	**Total Station Service**	90	67	65	56	63	61
19	**Station Service - % of Gen.**	4.1%	3.2%	3.1%	2.8%	3.1%	3.0%
20	**Losses**	144	122	144	182	146	140
21	**Losses - % of Gen.**	6.6%	5.9%	6.9%	9.1%	7.1%	6.9%
22	**Total Generation**	**2,188**	**2,057**	**2,079**	**2,004**	**2,049**	**2,022**
	Source						
23	Diesel Generation (MWh)	2,188	2,057	2,079	2,004	2,049	2,022
24	Diesel Efficiency (KWh/L)	3.52	3.46	3.47	3.63	3.63	3.63
25	Liters (000s)	622	594	599	552	565	557
	Peak						
26	Peak Load (KW)	436	418	412	385	403	396
27	Load Factor	57%	56%	58%	59%	58%	58%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.10

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

710 Arctic Bay

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,440	1,452	1,486	1,480	1,499	1,533
2	Customers	242	228	231	229	233	238
3	Av. MWh Sales/Cust.	5.95	6.37	6.43	6.47	6.42	6.44
4	Revenue (000s)	1,318	1,314	1,348	1,340	1,367	1,399
5	Cents/kWh	91.50	90.50	90.75	90.51	91.23	91.22
	Commercial						
6	Sales (MWh)	1,397	1,334	1,361	1,459	1,403	1,434
7	Customers	65	60	60	60	61	62
8	Av. MWh Sales/Cust.	21.49	22.23	22.69	24.18	23.03	23.30
9	Revenue (000s)	1,151	1,093	1,126	1,302	1,159	1,184
10	Cents /kWh	82.40	81.93	82.69	89.22	82.61	82.55
	Streetlights						
11	Sales (MWh)	34	34	34	34	34	34
12	Revenue (000s)	41	40	41	41	41	41
13	Cents /kWh	120.00	119.01	120.00	120.00	120.00	120.00
	Total						
14	**Sales (MWh)**	**2,871**	**2,819**	**2,881**	**2,973**	**2,936**	**3,001**
15	Customers	307	*288*	291	289	294	300
16	Revenue (000s)	2,509	2,447	2,514	2,682	2,567	2,623
17	Cents /kWh	87.41	86.79	87.28	90.21	87.44	87.40
	GENERATION (MWh)						
18	**Total Station Service**	70	78	78	86	79	80
19	**Station Service - % of Gen.**	2.2%	2.5%	2.4%	2.6%	2.4%	2.4%
20	**Losses**	234	219	235	302	248	250
21	**Losses - % of Gen.**	7.4%	7.0%	7.4%	9.0%	7.6%	7.5%
22	**Total Generation**	**3,175**	**3,116**	**3,194**	**3,361**	**3,263**	**3,331**
	Source						
23	Diesel Generation (MWh)	3,175	3,116	3,194	3,361	3,263	3,331
24	Diesel Efficiency (KWh/L)	3.61	3.62	3.61	3.54	3.54	3.54
25	Liters (000s)	879	862	883	949	922	941
	Peak						
26	Peak Load (KW)	677	648	688	690	669	689
27	Load Factor	54%	55%	53%	56%	56%	55%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.11

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

711 Clyde River

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,751	1,746	1,766	1,775	1,845	1,858
2	Customers	274	261	280	281	286	292
3	Av. MWh Sales/Cust.	6.39	6.69	6.31	6.33	6.44	6.36
4	Revenue (000s)	1,434	1,417	1,436	1,449	1,511	1,523
5	Cents/kWh	81.93	81.14	81.29	81.62	81.91	81.96
	Commercial						
6	Sales (MWh)	1,614	1,612	1,669	1,570	1,585	1,625
7	Customers	71	73	69	68	68	69
8	Av. MWh Sales/Cust.	22.73	22.09	24.19	23.17	23.15	23.50
9	Revenue (000s)	1,182	1,105	1,232	1,152	1,164	1,193
10	Cents /kWh	73.21	68.53	73.82	73.38	73.47	73.40
	Streetlights						
11	Sales (MWh)	25	25	25	25	25	25
12	Revenue (000s)	36	35	36	36	36	36
13	Cents /kWh	139.84	138.75	139.85	139.85	139.84	139.84
	Total						
14	**Sales (MWh)**	**3,390**	**3,384**	**3,461**	**3,371**	**3,455**	**3,509**
15	Customers	345	*334*	349	348	355	361
16	Revenue (000s)	2,652	2,557	2,704	2,637	2,711	2,752
17	Cents /kWh	78.21	75.57	78.12	78.23	78.47	78.41
	GENERATION (MWh)						
18	**Total Station Service**	85	85	89	93	88	90
19	**Station Service - % of Gen.**	2.2%	2.2%	2.3%	2.5%	2.3%	2.3%
20	**Losses**	327	332	381	328	321	321
21	**Losses - % of Gen.**	8.6%	8.7%	9.7%	8.6%	8.3%	8.2%
22	**Total Generation**	**3,802**	**3,801**	**3,931**	**3,792**	**3,863**	**3,920**
	Source						
23	Diesel Generation (MWh)	3,802	3,801	3,931	3,792	3,863	3,920
24	Diesel Efficiency (KWh/L)	3.67	3.58	3.69	3.76	3.76	3.76
25	Liters (000s)	1,036	1,063	1,064	1,008	1,028	1,043
	Peak						
26	Peak Load (KW)	796	810	766	796	789	808
27	Load Factor	55%	54%	59%	54%	56%	55%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.12

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

712 Grise Fiord

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	341	330	320	354	321	316
2	Customers	67	67	65	65	63	61
3	Av. MWh Sales/Cust.	5.09	4.93	4.93	5.47	5.11	5.17
4	Revenue (000s)	364	325	335	355	347	341
5	Cents/kWh	106.89	98.49	104.53	100.35	108.11	108.06
	Commercial						
6	Sales (MWh)	708	714	723	672	686	676
7	Customers	45	44	43	43	42	42
8	Av. MWh Sales/Cust.	15.74	16.22	16.80	15.70	16.24	16.25
9	Revenue (000s)	802	784	787	735	760	749
10	Cents /kWh	113.28	109.82	108.89	109.31	110.77	110.79
	Streetlights						
11	Sales (MWh)	23	23	23	23	23	23
12	Revenue (000s)	32	32	32	32	32	32
13	Cents /kWh	137.30	136.22	137.30	137.30	137.30	137.30
	Total						
14	**Sales (MWh)**	**1,072**	**1,067**	**1,066**	**1,050**	**1,030**	**1,015**
15	Customers	112	*111*	108	108	105	103
16	Revenue (000s)	1,199	1,141	1,153	1,122	1,139	1,122
17	Cents /kWh	111.77	106.89	108.20	106.90	110.54	110.55
	GENERATION (MWh)						
18	**Total Station Service**	58	37	41	39	38	36
19	**Station Service - % of Gen.**	4.6%	3.0%	3.3%	3.1%	3.2%	3.0%
20	**Losses**	134	127	130	162	144	142
21	**Losses - % of Gen.**	10.6%	10.3%	10.5%	13.0%	11.9%	11.9%
22	**Total Generation**	**1,265**	**1,231**	**1,237**	**1,251**	**1,212**	**1,193**
	Source						
23	Diesel Generation (MWh)	1,265	1,231	1,237	1,251	1,212	1,193
24	Diesel Efficiency (KWh/L)	3.47	3.72	3.43	3.56	3.56	3.56
25	Liters (000s)	365	331	361	351	341	335
	Peak						
26	Peak Load (KW)	261	209	221	209	221	214
27	Load Factor	55%	67%	64%	68%	63%	64%

Note: Revenues do not include fuel rider revenues/refunds.

Schedule A-3.13

Qulliq Energy Corporation
2018/19 General Rate Application
Summary of Generation, Sales, and Revenue

713 Sanikiluaq

Line no.	Description	2014/15 GRA Forecast	2014/15 Actual	2015/16 Actual	2016/17 Preliminary Actual	2017/18 Forecast	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE						
	Domestic						
1	Sales (MWh)	1,626	1,589	1,628	1,655	1,685	1,706
2	Customers	259	232	237	243	246	249
3	Av. MWh Sales/Cust.	6.28	6.85	6.87	6.81	6.84	6.84
4	Revenue (000s)	1,393	1,349	1,383	1,424	1,439	1,457
5	Cents/kWh	85.69	84.91	84.94	86.05	85.41	85.41
	Commercial						
6	Sales (MWh)	1,644	1,724	1,803	1,867	1,841	1,865
7	Customers	78	76	78	79	80	80
8	Av. MWh Sales/Cust.	21.08	22.68	23.11	23.60	23.13	23.28
9	Revenue (000s)	1,362	1,411	1,490	1,541	1,522	1,541
10	Cents /kWh	82.83	81.86	82.67	82.56	82.66	82.63
	Streetlights						
11	Sales (MWh)	33	33	33	33	33	33
12	Revenue (000s)	35	35	35	35	35	35
13	Cents /kWh	105.01	104.11	105.01	105.01	105.01	105.01
	Total						
14	**Sales (MWh)**	**3,303**	**3,346**	**3,464**	**3,555**	**3,559**	**3,604**
15	Customers	337	*308*	315	322	326	330
16	Revenue (000s)	2,790	2,795	2,908	3,000	2,996	3,033
17	Cents /kWh	84.46	83.53	83.95	84.39	84.17	84.15
	GENERATION (MWh)						
18	**Total Station Service**	84	81	74	83	83	83
19	**Station Service - % of Gen.**	2.3%	2.2%	2.0%	2.2%	2.2%	2.1%
20	**Losses**	239	198	181	199	201	193
21	**Losses - % of Gen.**	6.6%	5.5%	4.9%	5.2%	5.2%	5.0%
22	**Total Generation**	**3,626**	**3,624**	**3,718**	**3,837**	**3,843**	**3,881**
	Source						
23	Diesel Generation (MWh)	3,626	3,624	3,718	3,837	3,843	3,881
24	Diesel Efficiency (KWh/L)	3.67	3.70	3.77	3.72	3.72	3.72
25	Liters (000s)	988	980	985	1,032	1,033	1,043
	Peak						
26	Peak Load (KW)	754	758	718	725	757	762
27	Load Factor	55%	55%	59%	60%	58%	58%

Note: Revenues do not include fuel rider revenues/refunds.

APPENDIX B

CAPITAL ADDITIONS

TABLE OF CONTENTS

B1.0 INTRODUCTION

Appendix B summarizes actual capital spending for 2014/15-2016/17 and forecast spending for 2017/18-2018/19. This appendix also provides details for projects over $400,000 including those projects with major project permits approved by the Minister.

B2.0 ACTUAL CAPITAL PROJECTS OVER $400,000 IN 2014/15

The following section summarizes capital additions over $400,000 in 2014/15. Schedule B-1 shows the total capital additions in 2014/15 for projects greater than $100,000.

Rankin Inlet Distribution Upgrade – Replace Poles in Downtown Core $840,000

The project was undertaken to maintain reliability of service in the community. The project came into service in 2015.

The community of Rankin Inlet is experiencing notable growth in power demand. The growth in the community's electricity demand has changed the requirement for load allocation between the distribution system feeders. As such, the load allocations between the feeders were rebalanced, which required replacement of a number of poles in the community and downtown core. Further, the joint use spacing did not meet requirements on many of the poles and had become an issue. Replacing the poles and installing with the correct joint use spacing has reduced risks of live line wire contact and electrical shock, reduced risk of vehicular traffic contact with the pole and live wires, and allowed for additional equipment room as load grows in the area.

Rankin Inlet Ventilation System Upgrade $710,000

The project was undertaken to provide safe and reliable service. The project was capitalized April 1, 2015.

The plant at Rankin Inlet had been generating power with a sub-optimal supply of combustion air to the engines with a negative pressure inside the power house. The sub-optimal combustion air supply decreases the fuel efficiency and negative pressure draws in dust and dirt from outside the plant. This resulted in poor operational conditions and an accelerated depreciation of the equipment and assets inside the power house. To operate the genset engines with better fuel efficiency and to decrease the life cycle costs of the engines, it was recommended to upgrade the air handling system.

The project involved the addition of one new air handling unit (AHU-2), its shelter, exterior duct work, associated hydronic piping, removal of two existing 24-inch air fans and addition of four (30-inch) new fans in the plant building. The installation of the new AHU-2 has provided improved volume, filtration and temperature of combustion air to the existing engine (G3) and new engine (G4). The addition of four new fans has improved the ventilation conditions inside the plant.

Iqaluit Plant Expansion Upgrades $633,000

This project was partially capitalized in 2013/14 in the amount of $40.440 million for a total project cost of $41.073 million. This project was undertaken to meet the Corporation’s required firm capacity planning criteria and to ensure continued safe and reliable service in the community. This project received a major project permit dated March 11, 2011 (report 2011-02). This project was implemented to expand and upgrade the Iqaluit main plant to accommodate two new engine bays, two new 5 MW gensets, upgrading of ancillary systems, and renovate/retrofit the main plant offices and exterior.

The City of Iqaluit experienced significant load growth over the past 10 years and required additional generating capacity. The Iqaluit Main power plant was constructed in the early 1960's and the aging equipment and infrastructures needed to be upgraded to meet the increased energy demand.

Benefits of the project, also identified in the major project permit application to the URRC on March 11, 2011 (Report 2011-02), include:

1. Replacement/upgrading of equipment and/or systems at the end of their useful service life;
2. Improved power system reliability and stability;
3. Improved power quality to customers;
4. Environmental benefits; and
5. Ability to meet forecasted demand.

Pangnirtung Temporary/Emergency Generation Projects $1,052,000

The project was undertaken to maintain reliability and quality of service in the community.

This project involved the installation of temporary and emergency gensets as a result of the fire that destroyed the Pangnirtung power plant. The project was completed to restore power and ensure the community had reliable power during the construction of the new power plant.

Pond Inlet Genset Replacement $2,069,000

The project was undertaken to maintain reliability of service in the community. The project came into service in 2015. The project replaced CAT D399 with a 600 kW (nominal capacity) genset.

The Pond Inlet plant had experienced a number of outages prior to the project. Outages were related to gensets CAT D3512 and CAT D399. Both units were old and/or had incurred significant operating hours. The CAT D3512 was 19 years old and utilized extensively in the operating line-up due to its size and relative fuel efficiency. The CAT D399 was 28 years old and used less extensively due to reliability and relative fuel inefficiency. In order to improve efficiency and reliability at the facility, it was proposed to modernize the engine line-up by replacing the 28 year old CAT D399 with a more modern and efficient genset. As it was anticipated that this unit would be replaced at its next major overhaul, within five years, by advancing the replacement the overhaul and continued maintenance of this aged piece of equipment could be avoided. With the replacement of genset CAT D399 the CAT D3512 genset was placed fourth in the dispatch order and received minor maintenance to keep the unit operating reliably. By doing so, the life of the unit was extended for another five plus years before it will require replacement.

Igloolik **Genset Replacement** **$1,978,000**

This project was undertaken to meet long-term required firm capacity (RFC)[1] and improve overall reliability of service.

The replacement of the G-1 CAT D398 genset in Igloolik was required to meet RFC criteria. The replaced genset was a 26 years old CAT D398 (rated at 540 kW) and had reached the end of its service life and started approaching a major overhaul. The cost of the major overhaul was anticipated to exceed $275,000.

	Existing		Forecast					
Year	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Peak (kW)	1,118	1,142	1,203	1,249	1,293	1,310	1,328	1,347
110% of Peak (kW)	1,230	1,256	1,323	1,374	1,422	1,441	1,460	1,482
IFC - Existing (kW)	1,340	1,340	1,340	1,340				
IFC - Proposed (kW)				1,520	1,520	1,520	1,520	1,520

Notes: IFC – installed firm capacity, refers to the installed capacity with the largest unit out of service.

In 2012/13, the RFC (110% of Peak) exceeded the IFC existing (kW), thus the project involved the replacement of existing CAT D398 with a 950 kW to 1,000 kW genset.

[1] Required firm capacity is the installed capacity required to meet 110% of Peak with the largest unit out of service.

B3.0 ACTUAL CAPITAL PROJECTS OVER $400,000 IN 2015/16

The following section summarizes capital additions over $400,000 in 2015/16. Schedule B-2 shows the total capital additions for 2015/16 for projects greater than $100,000.

Arviat Genset Replacement $1,987,000

The project was undertaken to maintain reliability of service in the community. The project came into service in 2015.

Arviat generator G1 D3512 had reliability problems and required replacement with a more reliable unit of similar capacity as Arviat did not require a capacity increase. G1 had 80,960 hours of operation despite being installed in 1995. The replacement of G1 required minimal changes to plant and equipment systems. G1 was replaced with an 800 kW unit.

Whale Cove Airport Feeder Replacement $1,632,000

This project involved upgrading and relocating the airport feeder in Whale Cove. The project came into service in September 2015. This project was undertaken to ensure the Corporation can continue to provide safe and reliable service in the community.

The poles and equipment used in this feeder no longer met QEC standards and many had exceeded their useful life (+30 years). The 5 kV distribution line in place before the project began was not accessible by road with a bucket truck, which meant that linemen had to climb the poles physically to complete any pole top work. This increased maintenance and outage time and also put linemen at a risk for strain and fall injuries.

The project built a new feeder for the airport which follows the existing road and removed the old feeder. This allows maintenance crews quicker access to the lines in emergency situations, reduces outage time and cost, and reduces risk of injury.

Pangnirtung Temporary/Emergency Generation Projects $5,733,000

The project was undertaken to maintain reliability and quality of service in the community.

This project involved the installation of temporary and emergency gensets as a result of the fire that destroyed the Pangnirtung power plant. The project was completed to restore power and ensure the community had reliable power during the construction of the new power plant.

Resolute Bay Genset Replacement $827,000

This project was undertaken to ensure reliable service in the community. The project was capitalized April 1, 2015.

Emergency funds were needed to replace the 550 kW G3 Guascor engine in Resolute Bay. The 550 kW G3 Guascor engine failed when a rod went through the block at 17,400 hours. A capacity shortfall would have occurred if this unit was not replaced. The new engine installed was a MTU 8V4000 unit. Arrangements had been made with the contractor to install and test the engine to ensure its suitability and reliability.

Qikiqtarjuaq Capital Lease 50 Years $652,000

This project was undertaken to ensure the corporation can continue to provide safe and reliable electricity service in the community. The project lease commenced on June 1, 2014.

The previous Qikiqtarjuaq power plant was approaching 50 years and had major structural and operational issues that could not be remedied by installing new engines or attempting to “overhaul” the existing building. In March 2011, the Corporation submitted a project permit application to build a new power plant in Qikiqtarjuaq. The project was granted a major project permit by Ministerial Order dated June 9, 2011 as recommended in the URRC’s report 2011-05 from June 6, 2011. A land lease was required to build the new power plant land and a 50-year agreement was made with the Municipal Corporation of the Hamlet of Qikiqtarjuaq, beginning on June 1, 2014. The lease is solely for industrial purposes of the new Qikiqtarjuaq power plant. The new Qikiqtarjuaq plant was capitalized in 2016/17.

Sanikiluaq Distribution System Replacement $1,179,000

This project was undertaken to ensure the Corporation can continue to provide safe and reliable electricity service in the community.

This project involved replacing corroded tank pole mount transformers, re-conductoring primary and secondary distribution circuits and replacing vintage pole structures. It also replaced plant substation power transformers and associated equipment that is currently in disrepair and overloaded during peak load periods.

The previous Sanikiluaq overhead distribution system was an aged infrastructure and had substantial issues. A majority of the poles had exceeded their life expectancy. A number of the transformers were in very poor condition and posed safety, environmental, and operational risks. Sections of both the primary and secondary system were also aged and needed upgrades.

The new distribution system meets QEC's current Distribution Standard for transformer and secondary system design. These standards will help support a maintenance program for transformer replacements in the future.

B4.0 ACTUAL CAPITAL PROJECTS OVER $400,000 IN 2016/17

The following section summarizes actual capital additions over $400,000 in 2016/17. Schedule B-3 shows the total capital additions for 2016/17 for projects greater than $100,000.

Nunavut SCADA Upgrade Phase I $1,126,000

This project was undertaken to improve reliability and quality of service in all QEC power plants.

A supervisory control and data acquisition (SCADA) system was acquired and implemented in all QEC power plants in a phased manner. SCADA facilitates gathering, monitoring, retrieval and storage of data, and the control of equipment. SCADA is the backbone for other associated projects like AMI (automated metering infrastructure), DSM (demand side management), renewable energy, and Smart grid initiatives. The project has been divided into three phases for better project control and management.

Phase I consists of the Iqaluit and Kitikmeot region, Phase 2 consists of Taloyoak and Kivalliq region, and Phase 3 consists of the Baffin region. Phase 2 and Phase 3 have not yet started. Phase I was capitalized in 2016/17.

Cambridge Bay CHARS Capacity Increase $3,191,000

This project was undertaken to increase capacity, improve reliability and quality of service in the community. QEC received customer contributions of $0.5 million towards this project. This project has additional spending forecast in 2017/18 of $0.7 million for a total project cost of $3.9 million net of customer contributions [total project cost is $4.4 million].

A firm capacity increase was needed at the Cambridge Bay plant to address the load required for the Canadian High Arctic Research Station (CHARS) campus and the associated projected load growth of the community. Installation of a prefabricated building (outside existing power plant and within QEC property boundaries) to house one 1,100 kW generator set, 5kV switchgear and the engine and ancillary control panels. A remote radiator was supplied with the engine and unit will utilize existing plant fuel tank, which has been electrically interconnected with the existing plant switchgear line-up and load sharing lines, including alarms and economical dispatch. Furthermore, this setup can be used as a backup emergency unit in the event of main plant failure. This set-up has allowed Cambridge Bay plant to meet the immediate and long term load demand for CHARS and the community.

CHARS research station came into service in 2016/17. In conjunction with the capacity increase, QEC installed a dedicated distribution line for the CHARS campus as the current distribution system could not accommodate load requirements. The costs of the dedicated line were directly recovered from CHARS.

Taloyoak Plant Replacement $15,815,000

This project was undertaken to ensure the Corporation could continue to provide safe and reliable electricity service to the community. In March 2011, the Corporation submitted a project permit application to build a new power plant in Taloyoak. The project was granted a major project permit by Ministerial Order dated June 9, 2011 as recommended by the URRC report 2011-04 from June 6, 2011. The plant came into service in 2016/17. An additional plant replacement cost of $99,000 will occur in 2017/18.

The Taloyoak power plant was constructed in 1971. The structure was close to 45 years old by the time the new facility was constructed and had major structural and operational issues that could not be remedied simply by installing new engines or attempting to “overhaul” the existing building. The new power plant resolved the previous deficiencies at the generating station.

Rankin Inlet Fuel Supply Line Upgrade $784,000

This project was undertaken to improve environmental conditions and provide safe service in the community.

The Canadian Council of Ministers of the Environment (CCME) developed guidelines for bulk fuel systems in 2004 and in June 2008 the guideline became law under CEPA. Rankin Inlet, under the new laws, upgraded its singled walled pipeline and spill containment with a secondary containment. The project involved updating 460 metres of single walled pipeline running underground to double walled with a spill box at the manifold to catch escaped fuel and upgrading of spill containment at the marine manifold to interstitial monitoring for leak detection and secondary containment. The project was completed in 2016/17.

Naujaat Generator Switchgear Repair $501,000

This project was undertaken to improve reliability, ensure safety, and provide quality of service in the community. The project was capitalized in 2016/17.

The Naujaat plant switchgear was damaged by a failed component resulting in a fire on January of 2014. QEC maintenance made repairs to the affected equipment and returned the unit to operation. The next summer a thorough cleaning of the switchgear and bus bars revealed significant build-up of soot in the surrounding area around the G2 circuit break that was not found at the time of the initial repairs. The fire unknowingly caused the insulation to break down. In June 2014 the broken down insulation and soot build-up allowed for carbon tracking resulting in the failure of components and short circuiting within the G2 switchgear cell. Repairs were made to the genset. This project involved repairing the switchgear to ensure continued operation and reliability.

Iqaluit **AMI Smart Grid** **$1,637,000**

This project was undertaken to improve reliability and service quality in the community. QEC received approximately $1.3 million in Federal contributions towards this project [total project cost is $2.9 million]. The cost shown in Schedule B-3 are net of contributions.

QEC implemented “Smart Grid” technology to optimize the benefits of converting the Iqaluit distribution system from 4.16 kV to 25 kV and upgrading the Iqaluit main power plant. This project involved smart grid technology comprised of a bi-directional automatic meter reading (AMR) system with demand management system strategies. The project involved the installation of 4,000 smart meters and a second TCU/150kVa transformer.

QEC has already successfully implemented a basic AMR in Qikiqtarjuaq that has been in operation for over 10 years. Replication of the project will be considered in other communities of Nunavut in the future.

Resolute Bay **Fuel Storage Upgrade** **$799,000**

This project was undertaken to improve environmental conditions and provide safe service in the community. The project was capitalized in 2016/17.

Resolute Bay’s fuel storage system required modifications to comply with updated CEPA Tank Regulations 2013SOR-2008-197. During the initial assessment of the fuel storage system it was found that the concrete berm was old and cracked and the poly liner had been exposed to the elements and had holes. There was no secondary spill containment system in place in case of a spill. The updated regulations required a secondary containment. An assessment of the fuel system was undertaken and determined the proper course of action was to install a new double walled tank. This has allowed QEC to fulfill its obligation to the updated regulation.

Qikiqtarjuaq Plant Replacement $16,038,000

This project was undertaken to ensure the Corporation can continue to provide safe and reliable electricity service in the community. An additional plant replacement cost of $121,000 will occur in 2017/18.

The previous power plant in Qikiqtarjuaq was approaching 50 years old and had major structural and operational issues that could not be remedied by installing new engines or attempting to “overhaul” the existing building. Of primary concern was the constant shifting of the building and its related structures resulting in misalignment and stress placed on the structure, equipment, and piping connections. Station configuration, lot size and location, and soil stability limited upgrade options for the replaced power station site. For this reason, it was decided to build a new powerhouse.

In March 2011, the Corporation submitted a project permit application to build a new power plant in Qikiqtarjuaq. The project was granted a major project permit by Ministerial Order dated June 9, 2011 as recommended in the URRC’s report 2011-05 from June 6, 2011. The plant came into service in 2016/17.

Kimmirut **Generator Replacement** **$1,427,000**

This project was undertaken to improve reliability and provide adequate additional power to meet future projected power requirements.

Kimmirut generator G1 D353 was at the end of its useful life with engine hours at approximately 100,000. Replacement of the genset with a unit of 360 kW came into service in 2016/17.

Clyde River **Generator Upgrade** **$1,591,000**

This project was undertaken to improve reliability and provide quality of service in the community. The project was capitalized in 2016/17.

Clyde River genset G2 D3508 (480 kW) was at the end of its useful life and was targeted for replacement. genset G2 had been chosen because it had approximately 96,000 operating hours. There is a small capacity increase requirement for Clyde River and installing a larger genset will address this issue. The replacement genset is a 550 kW engine.

Sanikiluaq **Generator Replacement** **$1,508,000**

This project was undertaken to improve reliability and provide quality of service in the community.

Sanikiluaq's generator G1 (12V2000) rated at 540 kW had reliability and operational concerns. Genset G1 had mechanical problems with fuel and coolant contaminating the engine oil. The genset G1 was replaced with a more reliable genset CAT 3508B

(550 kW) unit while meeting firm capacity needs. The generator came into service in 2016/17.

B5.0 FORECAST CAPITAL PROJECTS OVER $400,000 FOR 2017/18

The following section summarizes forecast capital additions over $400,000 for 2017/18. Schedule B-4 shows the total capital additions for 2017/18 for projects greater than $100,000.

Cambridge Bay CHARS Capacity Increase $695,000

This project was undertaken to improve capacity, reliability and quality of service in the community. This project had a partial capitalization, including $500,000 in customer contributions, in 2016/17 of $3,691,000 for a total project cost of $4.386 million. The cost shown in Schedule B-3 and the project summary for2016/17 Cambridge Bay CHARS Capacity Increase are net of customer contributions.

Cambridge Bay Generator Replacement and Upgrade $2,421,000

This project is being undertaken to improve reliability and quality of service in the community.

Cambridge Bay has experienced load growth, as well as the addition of the CHARS campus. The Cambridge Bay generator G3 CAT 3512 is at the end of its useful life and due to the expected load growth an upgrade will be required for the power plant and existing generator. Genset G3 has over 103,000 hours, despite being installed in 1992, with a nominal capacity of 720 kW. The genset will be upgraded to a 1.1 MW unit and implementation of genset will come into service for 2017/18.

Cambridge Bay Tower Site Upgrade $1,285,000

This project is being undertaken to improve reliability, safety, and quality of service in the community.

The tower site in Cambridge Bay provides essential communication services to the community, such as the Government of Nunavut email services and Coast Guard VHF radio. Currently, the pole line that provides power to the site is in substandard condition and in need of replacement. The poles are old and dry rotting. The dry rot problem can potentially lead to poles splitting, cracking, and falling in the event of high winds. Dry rot also poses issues for line crews safely climbing poles. The primary conductor is #6 copper, which is considered a substandard primary conductor. Although copper is an excellent conductor, it has poor mechanical properties compared to the current standard primary conductor of aluminum with steel core. Compared to aluminum, copper has a lower strength to weight ratio and higher elasticity. The proposed project will address these deficiencies.

Gjoa Haven Engine Replacement $1,823,000

This project is being undertaken to ensure reliable service in the community. The project is scheduled to be capitalized in 2017/18.

The 550 kW G3 Guascor engine in Gjoa Haven requires replacing. The engine has proven to be unreliable and maintenance costs (failed parts and high replacement costs) will be significant to keep the engine operating. The project will involve the installation of a new MTU 8V4000 unit.

Gjoa Haven Genset Upgrade $2,401,000

This project is being undertaken to increase capacity and provide reliable service for the community.

Gjoa Haven generator G1 CAT 2512 (720 kW) is reaching the end of its useful life with approximately 91,000 hours installed in 1995. Firm capacity has also determined the need for a capacity increase in approximately one year. Rather than replacing genset G1, an option to add an additional self-contained genset of 500-550 kW to the existing line-up of three gensets, with additional switch gear and breakers has been approved.

Rankin Inlet Genset Replacement $310,000

This project is being undertaken due to an accident that occurred in the plant. The project is scheduled to be capitalized for 2017/18. This project will receive approximately $1.8 million in insurance proceeds, for a total project cost of about $2.1 million.

This Project involves repair and recommissioning of Unit G5 at the Rankin Inlet power plant. On November 29 2016 unit G5 (EMD 8-710, 1,440 kW, installed in 2006) failed with serious damage to the engine block and has not been operational since. The community has a total installed power (including G5) of 5,710 kW. The plant would have difficulty satisfying the required firm capacity requirements without genset G5 being repaired or replaced.

Baker Lake Generator Replacement and Upgrade $2,787,000

This project is being undertaken to increase capacity and provide reliable service for the community.

Baker Lake genset G1 D3512 (800 kW) was installed in 1994 and is reaching the end of its useful life with approximately 98,000 operating hours. Based on community power forecasting, a capacity increase is required within two years. This project involves replacing G1 with a 1,100 kW genset, increasing capacity by 300 kW. Installation will occur in 2017/18.

Arviat Generator Replacement $3,016,000

This project is being undertaken to improve reliability in the community.

Arviat's G3 CAT 3516 (960 kW) generator has problems with reliability and is nearing the end of its useful life based on operating hours. G3 was installed in 1994 and has over 85,000 operating hours. Based on current load forecasts Arviat does not require a capacity increase. The project involves replacing G3 with a more reliable unit of similar capacity. A genset replacement for G3 of nominal capacity of 960 kW will present minimal changes to plant equipments and systems.

Arviat Fuel Tank Replacement and Berm Removal $1,628,000

This project is being undertaken to improve reliability, improve environmental conditions and provide safe service in the community.

Arviat's fuel storage tanks are approximately 30 years old and at the end of their useful life. The project will involve the replacement of the fuel storage tanks with three 90,000 litre double walled tanks. Double walled tanks are needed to comply with CEPA regulations requiring secondary spill containment. The project will be completed in 2017/18.

Naujaat **Emergency Generator Set** **$2,643,000**

This project is being undertaken to improve reliability and quality of service in the community.

The plant in Naujaat will need an emergency generator set as part of the Emergency Response Plan. This project involves procurement and installation of a 340 kW emergency generator set in Naujaat in a mobile self-contained building with its own fuel supply and cooling capabilities. The genset will connect to one of the town feeders for emergency purposes. The emergency generator set is part of the QEC emergency response plan in case the power plant is lost due to a catastrophic failure such as fire, failure of major electrical equipment, such as switchgear, DC system and station service transformer. In addition, the emergency generator set will serve as a backup for the current engine line-up in case one of the plant engines is scheduled for major overhaul. The project has the advantage of meeting the emergency response plan and securing a firm capacity during major overhauls. Further, due to the short length of the community runway, a backup genset cannot be delivered by aircraft, which puts this community at a greater risk if an emergency genset is not onsite.

Naujaat **Generator Upgrade** **$2,427,000**

This project is being undertaken to improve reliability, capacity, and quality of service in the community.

Naujaat requires an upgrade to capacity. The current required firm capacity is 860 kW with a load forecast projection in 2020/2021 of approximately 899 kW. G2 is a series 60 genset (320 kW) with approximately 18,700 hours. It is the smallest of the three gensets and therefore is the target for the upgrade. A 550 kW genset that has been purchased for Hall Beach will be shipped to Naujaat in order to expedite the installation in Naujaat and will replace the G2 320 kW genset. The existing 320 kW genset does have some service life remaining and will be re-utilized elsewhere. The capacity upgrade will require some changes and upgrade to the circuit breaker and other load sharing devices. In addition, modification of the radiator fan structure may be required to accommodate a new radiator fan. The target completion for this project is the fall of 2018.

Iqaluit **Main Plant Fire Pump** **$859,000**

This project is being undertaken to provide safe and reliable service in the community. The project is scheduled to be capitalized for 2017/18.

This project involves the procurement and installation of a self-housed diesel operated fire pump that will supply a source of water to the Iqaluit main power plant wet fire suppression system. The project is needed so the fire pump system can operate automatically in the event of an emergency fire situation and to meet the requirements from the fire marshal's office to comply with codes and regulations. The fire pump system is to be located on the City of Iqaluit land adjacent to the reservoir building where an adequate volume of water is stored for the purposes of fire protection at the main plant. The power plant currently has a water based sprinkler system within the office area, three hose cabinets, and three fire department connections. The fire piping is to be routed via an underground concrete passageway from the City of Iqaluit reservoir building to the Iqaluit main power plant.

Iqaluit Fuel Room Upgrade at Main Plant $968,000

This project is being undertaken to improve reliability and quality of service in the community. The project is scheduled to be capitalized in 2017/18.

An upgrade to the centrifuges (separators) at the Iqaluit main plant fuel supply system is required as they are approaching 30 years old. Upon review and inspection of the Iqaluit main plant fuel supply system it was found that the existing fuel cleaning centrifuges do not keep up with the fuel demand and the fuel is flowing through the system without being properly cleaned. This results in the contaminants that are not separated out of the fuel going into the engines, wearing down components, and potentially causing premature failure. To correct this centrifuges will be upgraded.

Iqaluit LED Street Light Replacement $503,000

This project is being undertaken to reduce energy consumption and increase quality of service. The project is scheduled to be capitalized for 2017/18.

This project involves the City of Iqaluit replacing its high pressure sodium [HPS] streetlights with LED streetlights. LED streetlights have proven to be more energy efficient resulting in a reduction of energy consumed and have proven to last longer than HPS streetlights resulting in potential maintenance cost savings.

Pangnirtung Power Plant Replacement $19,022,000

This project is for the replacement of the existing power plant in Pangnirtung that was damaged by a fire in April 2015.This project is being undertaken to ensure reliability, capacity, and quality of service in the community.

The original power plant was constructed in 1971 and consisted of three Caterpillar gensets: G1 3512B (950 kW), G2 3516 (960 kW) and G3 3512 (720 kW). The 2014/15 peak load for the community is approximately 1,365 kW, with power distributed on two electrical feeders. The power plant was damaged to the extent that it required complete removal and replacement. The existing building foundation was not extensively damaged by the fire, but was determined that the foundation be removed as the best foundation for a new plant is to utilize piles. Insurance will cover $18 million of the power plant replacement.

Resolute Bay Feeder Conversion $1,519,000

This project is being undertaken to improve reliability and quality of service in the community.

The feeder supplying the main camp in Resolute Bay is a 2.4 kV ungrounded delta connected system. Delta connected systems are being phased out from QEC distribution systems. Ungrounded delta connected systems face over voltages and do not have suitable or adequate protection in QEC distribution system. The infrastructure of this feeder is over 30 years old and is in need of replacement.

This project will convert the existing 2.4 kV delta system supplying the main camp area of Resolute Bay to a 12.4 kV multi-ground Wye system. This will also involve replacement of aging poles and infrastructure, and the addition of storm guys to make the distribution lines more stable during extreme weather conditions.

Conversion from Delta to Wye will provide a more stable distribution system and better power quality for the end user. In addition, conversion of the underground feeders to overhead will allow for easier maintenance and upgrade the feeders to QEC's standards.

Pond Inlet **Fuel Storage Upgrade** **$1,188,000**

This project is being undertaken to improve environmental conditions and provide safe service in the community. The project is scheduled to be capitalized for 2017/18.

Pond Inlet's fuel storage system requires modifications to comply with updated regulations. The fuel storage system in Pond Inlet has two single wall tanks that were installed when the plant was built in 1984. The berm was constructed without a liner, therefore there is no secondary containment. Updated regulations require secondary containment. This project will involve two or three double walled tanks and a double walled direct line from the PPD tank farm. Completion of this project will ensure the fuel storage complies with the updated regulation.

Pond Inlet **Substation Upgrade** **$643,000**

This project is being undertaken to improve reliability and quality of service in the community. The project is scheduled to be capitalized for 2017/18.

This project involves the replacement of the substation power transformer, feeder reclosers, protection and control equipment, and associated civil works. The project will also include proper grounding and boding of the system to meet current utility practices. The project is being undertaken to accommodate future load growth, which the existing substation does not meet. The current substation power transformer bank used to supply the Pond Inlet distribution system consists of three 333 kVa single phase units with a total system capacity of 999 kVa. The power transformer supplies a bus to which three radial distribution feeders are connected via pole mounted recloser unit protecting each feeder. The 2014/15 peak load reached over 1,200 kVa. The maximum allowable peak load for the current setup is 1,298 kVa, thus the need to accommodate future load growth. Upgrades are also need as the existing unit transformer bank and recloser units are approximately 20 years. These units should be retired and replaced with new vacuum reclosers, which will align with current utility practice and will be much more economical to operate and maintain.

The project will involve the replacement of the unit transformer bank with a proper size three phase pad mounted transformer. In addition, all the existing feeder reclosers, protection and control equipment will be replaced with new equipment. This project will meet the immediate operation requirements, will improve on system reliability, and will address the community expandability and future load growth.

Hall Beach **Generator Upgrade** **$1,930,000**

This project is being undertaken to improve reliability, capacity, and quality of service in the community.

Hall Beach requires a capacity increase. G4 CAT D3508 (480 kW) has been selected as it has exceeded its useful life of 110,000 hours. A new genset rated at approximately 550 kW will provide an adequate power increase to satisfy future requirements.

Clyde River **Emergency Generator Unit** **$1,835,000**

This project is being undertaken to improve reliability and quality of service in the community.

The plant in Clyde River will need a 350 kW emergency generator (and will serve as back up to the current engine line-up) in case the Clyde River power plant is lost due to a catastrophic failure such as a fire, failure of major electrical equipment (e.g., switchgear, DC system and Station Service Transformer) or in case one of the plant engines, is schedule for major overhaul.

The purpose of this project is to procure a new mobile self-contained emergency generator set and install near the plant with its own fuel supply and cooling capabilities for the use in emergency situations. The generator set will be electrically connected to the plant for exercise and immediate availability during emergency situations.

Grise Fiord Distribution System Upgrade $642,000

This project is being undertaken to improve reliability, ensure safety, and quality of service in the community. The project is scheduled to be capitalized for 2017/18.

This project involves the conversion of the current 600 volt substandard overhead distribution system to 4,160 volts (5 kV class) to alleviate customer power quality problems associated with load growth and voltage drop. The existing overhead distribution system operates in the low voltage class of 600 volts and is configured as an ungrounded delta connected system. This type of ungrounded system is difficult to maintain and creates voltage stability issues when lightly loaded. The system also distributes voltage at the same plant with no system isolation, making it difficult to regulate voltage over peak load periods without substation transformer tap changers. This project will improve reliability and service quality.

B6.0 FORECAST CAPITAL PROJECTS OVER $400,000 FOR 2018/19

The following section summarizes forecast capital additions over $400,000 for 2018/19. Schedule B-5 shows the total capital additions in 2018/19 for projects greater than $100,000.

Iqaluit Bulk Fuel Tank Upgrade $2,910,000

This project is being undertaken to improve environmental conditions and provide safe service in the community.

The existing five million litre tank has been in service for approximately 23 years since it was last refurbished in 1994. The Iqaluit bulk fuel storage facility needs to be upgraded and its storage capacity increased to meet at least the next 25 year growth of the fuel consumption.

This project involves constructing a second 5.7 million litre fuel holding tank and upgrading this tank's fuel containment berm at the main power plant in Iqaluit. This is required to be installed and in service to maintain a fuel supply to plant before the existing tank can be taken out of service for inspection and reconditioning. In addition, the new tank will also increase storage capacity for the Iqaluit plant. By having a two tank configuration it ensures the plant has an adequate fuel supply in situations where one of the tanks has to be taken out of service for maintenance.

Iqaluit Fuel Supply Line Upgrade $1,979,000

This project is being undertaken to improve environmental conditions and provide safe and reliable service in the community.

The project will involve the replacement of 600 metres of existing single-walled fuel pipeline used for fuel deliveries to the Iqaluit plant. The existing pipeline was installed at least 40 years ago and is in poor condition. The existing pipeline runs aboveground and is located parallel to an existing roadway. Replacement of the existing fuel supply line will ensure a reliable fuel system for Iqaluit for the next 40 years.

Grise Fiord **New Power Plant** **$19,969,000**

This project is being undertaken to improve reliability and quality of service in the community.

The existing Grise Fiord power plant was constructed in 1963 and has numerous problems in regard to its civil, mechanical, and electrical systems. It suffers from several deficiencies, including failing building foundation, unreliable superstructure and aging systems and equipment. Given that the typical design life of a power generating facility is 40 years, the current Grise Fiord facility is passed its service life and requires replacement.

Schedule B-1: Actual Capital Additions for 2014/15

Schedule B-1

QULLIQ ENERGY CORPORATION
2018/19 GENERAL RATE APPLICATION
ACTUAL CAPITAL ADDITIONS FOR 2014/15
(in thousands of dollars)

Plant #	Plant Name	Description	2014/15 Additions ($000)				
			Diesel Plant	Distribution	General Plant	Total Project	Total for Plant
	Nunavut	New Phone System - Baker Lake, Cam Bay, Rankin			$155	$155	
							$155
601	Rankin Inlet	Replace Poles in Downtown Core		$840		$840	
		Install New Air Handling Unit	$710			$710	
							$1,550
701	Iqaluit	Plant Expansion(Add 2 Bays)Upgrades	$633			$633	
							$633
702	Pangnirtung	Temporary/Emergency Generation Projects	$1,052			$1,052	
							$1,052
705	Pond Inlet	Genset Replacement	$2,069			$2,069	
							$2,069
706	Igloolik	Genset Replacement	$1,978			$1,978	
							$1,978
707	Hall Beach	Line Truck - RBD			$222	$222	
							$222
711	Clyde River	Transient Trailer			$293	$293	
							$293
	Projects with cost less than $100,000		$268	$451	$643	$1,363	
							$1,363
		Total for QEC	**$6,710**	**$1,291**	**$1,313**	**$9,314**	**$9,314**

Schedule B-2: Actual Capital Additions for 2015/16

Schedule B-2

QULLIQ ENERGY CORPORATION
2018/19 GENERAL RATE APPLICATION
ACTUAL CAPITAL ADDITIONS FOR 2015/16
(in thousands of dollars)

Plant #	Plant Name	Description	2015/16 Additions ($000)				
			Diesel	Distribution	General Plant	Total Project	Total for Plant
505	Kugluktuk	Upgrade Fuel Tanks	$356			$356	
							$356
603	Arviat	Genset Replacement	$1,987			$1,987	
							$1,987
606	Whale Cove	Airport Feeder Upgrade		$1,632		$1,632	
							$1,632
701	Iqaluit	Book Truck			$164	$164	
							$164
702	Pangnirtung	Temporary/Emergency Generation Projects	$5,462	$271		$5,733	
							$5,733
704	Resolute Bay	Genset Replacement	$827			$827	
							$827
708	Qikiqtarjuak	Land & Rights	$652			$652	
		Transient Acc / Trailer			$392	$392	
							$1,044
709	Kimmirut	DC System Upgrade	$223			$223	
							$223
713	Sanikiluaq	Transient Trailer			$310	$310	
		Distribution System Replacement		$1,179		$1,179	
							$1,490
	Projects with cost less than $100,000		$140	$259	$411	$810	
							$810
		Total for QEC	**$9,648**	**$3,342**	**$1,277**	**$14,266**	**$14,266**

Schedule B-3: Actual Capital Additions for 2016/17

Schedule B-3

QULLIQ ENERGY CORPORATION
2018/19 GENERAL RATE APPLICATION
ACTUAL CAPITAL ADDITIONS FOR 2016/17
(in thousands of dollars)

Plant #	Plant Name	Description	2016/17 Additions ($000) Diesel	Distribution	General Plant	Total Project	Total for Plant
	Nunavut	Nunavut SCADA System	$1,126			$1,126	
							$1,126
501	Cambridge Bay	Capacity Increase	$3,191			$3,191	
		Truck			$251	$251	
							$3,441
503	Taloyoak	Plant Replacement	$15,339	$351	$125	$15,815	
							$15,815
601	Rankin Inlet	Fuel Supply Line Upgrade	$784			$784	
							$784
607	Naujaat	Generator Switchgear Repair	$501			$501	
		Truck			$251	$251	
							$751
701	Iqaluit	AMI/Smart Grid	$529	$1,108		$1,637	
		Transformer Safety Wall	$111			$111	
							$1,748
704	Resolute Bay	Fuel Storage Upgrade	$799			$799	
							$799
705	Pond Inlet	Quonset Garage/Warehouse			$133	$133	
							$133
708	Qikiqtarjuak	Plant Replacement	$15,306	$608	$125	$16,038	
		Truck			$252	$252	
							$16,291
709	Kimmirut	Genset Replacement	$1,427			$1,427	
							$1,427
711	Clyde River	Genset Upgrade	$1,591			$1,591	
							$1,591
713	Sanikiluaq	Genset Replacement	$1,508			$1,508	
							$1,508
	Projects with cost less than $100,000		$500	$1,707	$269	$2,476	
							$2,476
		Total for QEC	**$42,711**	**$3,774**	**$1,405**	**$47,890**	**$47,890**

Schedule B-4: Forecast Capital Additions for 2017/18

Plant #	Plant Name	Description	2017/18 Additions ($000)				
			Diesel	Distribution	General Plant	Total Project	Total for Plant
	Nunavut	Enterprise System Review			$278	$278	
							$278
501	Cambridge Bay	CHARS Capacity Increase	$695			$695	
		Genset Replacement and Upgrade	$2,421			$2,421	
		Tower Site Upgrade		$1,285		$1,285	
		Plant Structural Upgrade	$281			$281	
		Plant Fire Alarm System			$110	$110	
		LED Streetlight Replacement		$276		$276	
							$5,069
502	Gjoa Haven	Engine Replacement	$1,823			$1,823	
		Genset Upgrade	$2,401			$2,401	
							$4,224
503	Taloyoak	Plant Replacement [remaining cost]	$99			$99	
							$99
505	Kugluktuk	Plant Fire Alarm system			$100	$100	
		LED Streetlight Replacement		$244		$244	
							$344
601	Rankin Inlet	Engine Replacement [before insurance proceeds]	$2,068			$2,068	
		LED Streetlight Replacement		$293		$293	
							$2,360
602	Baker Lake	Genset Replacement and Upgrade	$2,787			$2,787	
		Fence	$372			$372	
							$3,159
603	Arviat	Genset Replacement	$3,016			$3,016	
		Fuel Tank Replacement and Berm Removal	$1,628			$1,628	
							$4,644
604	Coral Harbour	Upgrade Fuel Supply Line	$208			$208	
		RBD Line Truck			$250	$250	
		Quonset Garage			$396	$396	
							$854
606	Whale Cove	Fence	$314			$314	
		Plant Fire Alarm system			$100	$100	
							$414
607	Naujaat	Emergency Generator Set	$2,643			$2,643	
		Generator Upgrade	$2,427			$2,427	
		Quonset Garage			$396	$396	
		Fence	$319			$319	
							$5,784

Schedule B-5: Forecast Capital Additions for 2017/18 [cont.]

Plant #	Plant Name	Description	2017/18 Additions ($000)				
			Diesel	Distribution	General Plant	Total Project	Total for Plant
701	Iqaluit	Main Plant Fire Pump	$859			$859	
		Fuel Room Upgrade Main Plant	$968			$968	
		Waste Oil Burners for Plant	$257			$257	
		Fall Arrest System			$178	$178	
		Property Shop			$277	$277	
		LED Streetlight Replacement		$503		$503	
							$3,041
702	Pangnirtung	Plant Replacement [before insurance proceeds]	$19,022			$19,022	
							$19,022
704	Resolute Bay	Feeder Conversion		$1,519		$1,519	
							$1,519
705	Pond Inlet	Fuel Storage Upgrade	$1,188			$1,188	
		Substation Upgrade		$643		$643	
							$1,830
706	Igloolik	Fence	$217			$217	
							$217
707	Hall Beach	Capacity Increase	$1,930			$1,930	
		Quonset Type Garage / Warehouse			$236	$236	
		Transient Trailer			$322	$322	
							$2,489
708	Qikiqtarjuak	Quonset Type Garage / Warehouse			$104	$104	
		Plant Replacement [remaining cost]	$121			$121	
							$225
709	Kimmirut	Quonset Type Garage			$204	$204	
		Upgrade Fuel Supply Line	$153			$153	
							$357
710	Arctic Bay	RBD Line Truck			$270	$270	
							$270
711	Clyde River	Emergency Generator Unit	$1,835			$1,835	
		Fence	$294			$294	
							$2,129
712	Grise Fiord	Transient Unit			$300	$300	
		Distribution System Upgrade		$642		$642	
							$942
713	Sanikiluaq	Quonset Type Garage / Warehouse			$142	$142	
							$142
	Projects with cost less than $100,000				$1,029	$1,029	
							$1,029
		Total for QEC	**$50,345**	**$5,405**	**$4,692**	**$60,442**	**$60,442**

Notes:
1. Rankin Inlet Engine Replacement cost is before insurance proceeds of $1.8 million [the net impact to rate base is about $0.3 million].
2. Pangnirtung Plant Replacement cost is before insurance proceeds of $18.0 million [the net impact to rate base is about $1 million].

Schedule B-6: Forecast Capital Additions for 2018/19

Schedule B-5

QULLIQ ENERGY CORPORATION
2018/19 GENERAL RATE APPLICATION
FORECAST CAPITAL ADDITIONS FOR 2018/19
(in thousands of dollars)

Plant #	Plant Name	Description	2018/19 Additions ($000) Diesel	Distribution	General Plant	Total Project	Total for Plant
	Nunavut	IT Server Replacements			$233	$233	
							$233
501	Cambridge Bay	Upgrade Underground Fuel Supply Line	$281			$281	
							$281
502	Gjoa Haven	Fire Alarm System			$110	$110	
							$110
701	Iqaluit	New Bulk Fuel Tank Upgrade	$2,910			$2,910	
		Fuel Supply Line Upgrade	$1,979			$1,979	
							$4,889
704	Resolute Bay	Fire Alarm System			$110	$110	
							$110
712	Grise Fiord	New Power Plant	$19,446	$523		$19,969	
							$19,969
	Projects with cost less than $100,000				$500	$500	
							$500
		Total for QEC	**$24,616**	**$523**	**$953**	**$26,092**	**$26,092**

APPENDIX C

COST OF SERVICE STUDY METHODS

C1.0 OVERVIEW

C1.1 PURPOSE OF THE COST OF SERVICE

A cost-of-service (COS) study is an analytical tool that supports the ratemaking process. The purpose of a COS study is to develop a method to fairly allocate the revenue requirement among the different customer classes served by the utility. While there are many potential allocation methods, the core objective is to allocate costs to customers consistent with principles of cost causation based on customer characteristics such as energy consumption and peak demand.

There is no absolute right or wrong allocation method, as each utility's operating circumstances and cost drivers are different. The objective for the utility is to select methods which best represent cost causation and the equitable sharing of costs among customers in a manner appropriate for the unique circumstances of the utility. This document describes the COS study methods based on a territory-wide approach.

A COS study can provide useful information such as unit costs to serve different customers (such as $/kWh, $/customer month) and revenue to cost coverage ratios, which are used in the ratemaking process. However, it must be recognized that any COS study involves estimation and a degree of professional judgement and therefore the results cannot be considered exact. Further, the appropriate allocation methods for a COS study can change over time as the utility's operating environment and cost drivers change.

To provide services to its customers, the Corporation must receive sufficient revenues to recover its costs. The COS study used in this Application applies cost-of-service concepts to embedded accounting costs in order to calculate the fair share of the Corporation's total revenue requirement for each customer class.

C1.2 STEPS OF THE COST OF SERVICE PROCESS

The steps involved in a COS study are the following:

1. Determining a test period;
2. Determining revenue requirement;
3. Selecting customer classes;
4. Functionalization of plant and expenses;
5. Classification of plant and expenses; and
6. Allocation of plant and expenses.

Step 1: Determining a Test Period: The test period refers to the time period over which revenues and expenses are analyzed to determine the surplus or deficiency in rates. This COS study is for the test period of April 1, 2018 to March 31, 2019.

Step 2: Determination of Revenue Requirement: This COS study uses the proposed revenue requirement for the 2018/19 test year as described in the application.

Step 3: Selection of Customer Classes: A customer class is a group of customers with similar load characteristics. The classes used in this COS study are:[1]

[1] Definitions of the customer classes are provided in QEC Terms & Conditions of Service.

i). Domestic;

ii). Commercial; and

iii). Streetlighting.

Plant investment and expenses that serve only a particular customer or class of customers are directly assigned. For example, the plant investment and expenses associated with streetlights are directly assigned to the streetlighting class.

Once the revenue requirement and customer classes have been determined, the COS study is undertaken in a three-step process described below.

Functionalization: Once the revenue requirement and customer classes have been determined, plant investment and expenses are separated according to function. The functions used in QEC's COS study are:

i). Generation;

ii). Distribution; and

iii). General.

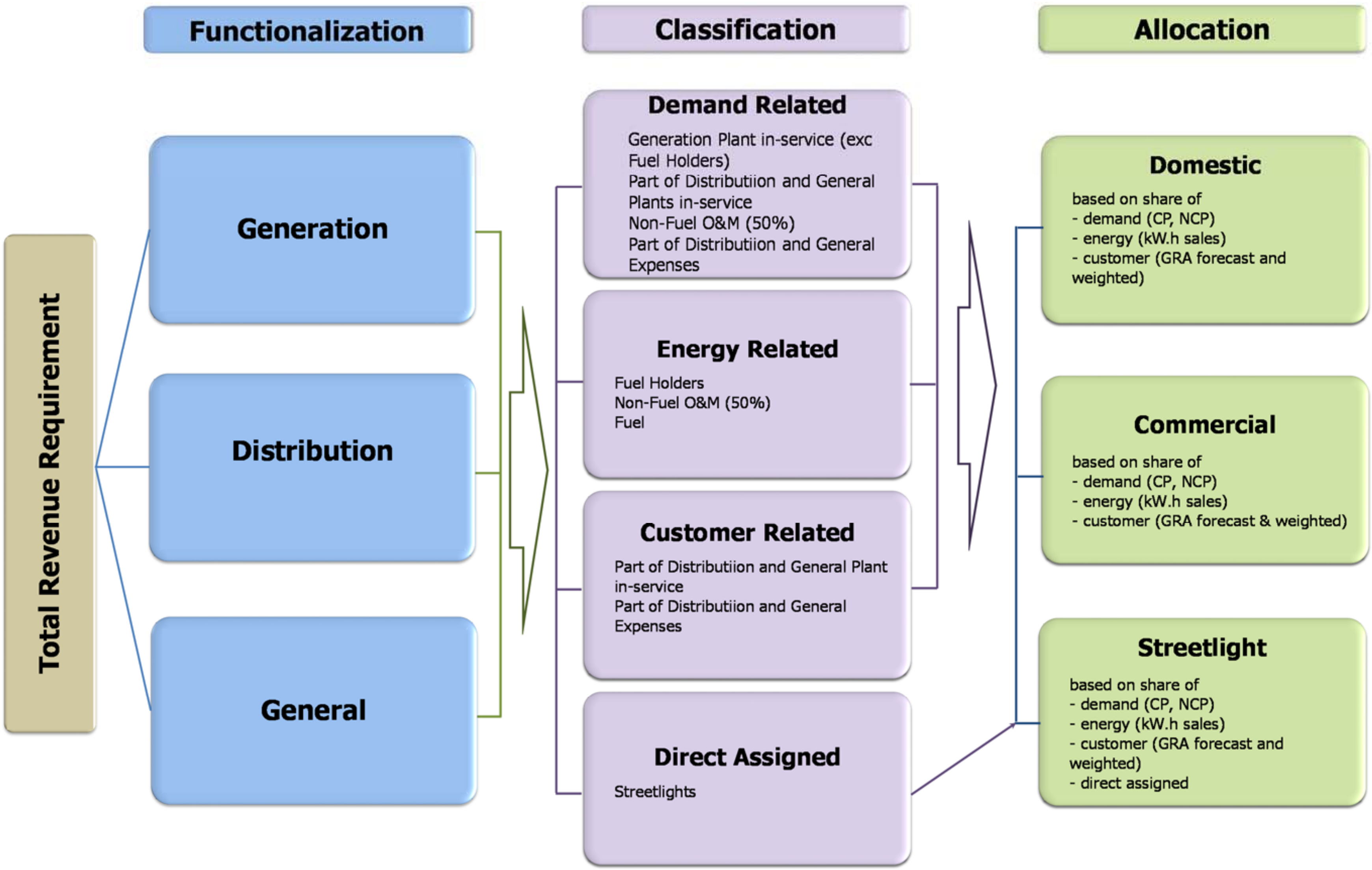
The assignment of plant investment and expenses to each function generally follows the utility's standard set of accounts. In the case of the Corporation, assets are coded to a series of functional categories based on Federal Energy Regulatory Commission ("FERC") codes. Functionalization is discussed further in Chapter 2.

Classification: This step in the COS process separates the functionalized costs into classifications based on the type of service provided. The three principal cost classifications for electric utilities are demand costs (costs that vary with the kW demand imposed by the customer), energy costs (costs that vary with the kWh of energy that the utility provides) and customer costs (costs that vary in relation to the number of customers served). Classification methods are discussed in greater detail in Chapter 3.

Allocation: The final step in the COS analysis is the allocation of classified costs to customer classes. For example, energy related costs have been allocated to customer classes based on energy usage in kilowatt-hours. The allocation factors developed for the COS study were derived using billing records, load records and the Corporation's proposed load forecast. Allocation is discussed in greater detail in Chapter 4.

Figure C1.1 provides an illustration of the steps involved in the Corporation's COS study.

Figure C1.1:
Illustrative Steps of the COS Study Process



C2.0 FUNCTIONALIZATION

The Corporation relies on diesel generation for electricity production. Each community's electricity system generally consists of a powerhouse for production facilities, distribution bus, distribution feeder system and general facilities. Currently, the Corporation does not have any transmission related assets. As such, the cost functions used in this COS study include:

Generation Function: The generation function consists of assets and expenses associated with power generation. The generation function includes power production facilities, operation and maintenance costs directly related to these facilities and production fuel expense.

Distribution Function: The distribution function includes assets and expenses that connect customers to the generation plant.

General Function: The general function includes management, administrative and other costs that cannot be assigned to the other major cost functions.

C2.1 FUNCTIONALIZATION OF PLANT

Functionalization of gross plant and accumulated amortization was carried out according to the FERC codes set out in Table C2.1, which is consistent with the 2010/11 GRA approach.

Table C2.1: Plant Functionalization

FERC Account Number		DESCRIPTION
EUG Plant		
121		Energy Utilization
131		Residual Heating System
DIESEL Plant		
340		Land and Land Rights
341		Structures & Improvements
342		Fuel Holders, Prod., & Access.
343		Prime Movers
344		Generators
345		Accessory Electric Equipment
346		Miscellaneous Power Plant Equipment
DISTRIBUTION Plant		
360		Land and Land Rights
361		Structures & Improvements
362		Station Equipment
363		Storage Battery Equipment
364		Poles & Fixtures
365		Overhead Conductors & Devices
366		Underground Conduit
367		Underground Conductors & Devices
368		Line Transformers
369		Services
370		Meters
371		Installation on Cust. Premises
372		Leased Property on Customer Premises
373		Street Lighting
GENERAL Plant		
383		Computer Software
389		Land and Land Rights
390		Structures & Improvements
391		Office Furniture & Equipment, Computers
392		Transportation Equipment
393		Stores Equipment
394		Tools, Shop, & Garage Equipment
395		Laboratory Equipment
396		Power Operated Equipment
397		Communication Equipment
398		Miscellaneous Equipment
399		Other Tangible Property

Fuel inventory amounts in working capital were functionalized to generation (consistent with the functionalization of fuel expense). Other working capital amounts were functionalized to general plant.

C2.2 FUNCTIONALIZATION OF EXPENSES

The Corporation's expense budget for the test year is prepared by each department and plant according to the budget codes set out in Tables C2.2 and C2.3.

Table C2.2:
QEC Departments

Budget Codes		DESCRIPTION
Head Office Department Codes		
1000/1100		Board & Iqaluit Admin
1200		Finance
1300		Corporate Affairs
1500		Human Resources
1600		Shared Services
1700		Property Management
2000		Territorial Operations
2250		Energy Management
2400		Health, Safety and Environment
2600		Information Technology
2700		Engineering
Regional Office Department Codes		
2100		Regional Operations
2500		Line
Communities		
2200		Plant Operations

The Corporation reviewed each of the budget expense items and determined an appropriate functionalization of each expense as illustrated in Table C2.3.

Table C2.3: Functionalization of QEC's Expenses

<table>
<tr><th>DESCRIPTION</th><th>Other head office departments</th><th>2000 - Territorial Operations</th><th>2100 - Regional Operations</th><th>2200 - Plant Operations</th><th>2500 - Line</th><th>2700 - Engineering</th></tr>
<tr><td>Salaries and Wages</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Regular</td><td rowspan="5">100% General Plant</td><td rowspan="5">61% Generation, 38% Distribution and 1% General Plant [based on positions]</td><td rowspan="5">73% Generation and 27% Distribution [based on positions]</td><td rowspan="5">70% Generation and 30% Distribution</td><td rowspan="5">100% Distribution</td><td rowspan="5">75% Generation, 23% Distribution and 1% General Plant [based on positions]</td></tr>
<tr><td>Regular Overtime</td></tr>
<tr><td>Casual</td></tr>
<tr><td>Casual Overtime</td></tr>
<tr><td>Employee Benefits</td></tr>
<tr><td>Supplies and Services</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Materials Purchased</td><td rowspan="33">100% General Plant</td><td>100% Generation</td><td>Based on Salaries</td><td rowspan="2">80% Generation and 20% Distribution</td><td rowspan="33">100% Distribution</td><td rowspan="33">Based on Salaries and Wages [75% Generation, 23% Distribution and 1% General Plant]</td></tr>
<tr><td>Freight</td><td>100% Generation</td><td>Based on Salaries</td></tr>
<tr><td>Vehicles</td><td></td><td>100% General</td><td>100% General</td></tr>
<tr><td>Tools, Furniture and Equipment < $2,500</td><td>100% General</td><td>100% General</td><td>100% General</td></tr>
<tr><td>Clothing and Safety Equipment</td><td>70% Generation, 30% Distribution</td><td>Based on Salaries</td><td>Based on Salaries</td></tr>
<tr><td>Office Supplies</td><td rowspan="21">100% General</td><td rowspan="21">100% General</td><td rowspan="21">100% General</td></tr>
<tr><td>Telephone</td></tr>
<tr><td>Building Rental (Non-Housing)</td></tr>
<tr><td>Heating Fuel (Non-Housing)</td></tr>
<tr><td>Water Sewer Garbage (Non-Housing)</td></tr>
<tr><td>Snow Removal</td></tr>
<tr><td>Building Rental (Housing)</td></tr>
<tr><td>Heating Fuel (Housing)</td></tr>
<tr><td>Water Sewer Garbage (Housing)</td></tr>
<tr><td>Repairs and Maintenance (Housing)</td></tr>
<tr><td>Rent Recovery (Housing)</td></tr>
<tr><td>Insurance (Non-Housing)</td></tr>
<tr><td>Municipal Taxes (Non-Housing)</td></tr>
<tr><td>Municipal Taxes (Housing)</td></tr>
<tr><td>Disposal of waste</td></tr>
<tr><td>Spill cleanup costs</td></tr>
<tr><td>Licenses, Fees and Dues</td></tr>
<tr><td>Advertising and Public Relations</td></tr>
<tr><td>Recruitment Costs</td></tr>
<tr><td>Translations</td></tr>
<tr><td>Performance Management/Leadership / Corporate Development</td></tr>
<tr><td>Training and IEP Program</td><td>Based on Salaries</td><td>Based on Salaries</td><td></td></tr>
<tr><td>Professional Fees-Legal</td><td>100% General</td><td>100% General</td><td>100% General</td></tr>
<tr><td>Outside Services</td><td>70% Generation, 30% Distribution</td><td>Based on Salaries</td><td>100% Generation</td></tr>
<tr><td>Overhauls</td><td>100% Generation</td><td>100% Generation</td><td>100% Generation</td></tr>
<tr><td>Computer services</td><td rowspan="2">100% General</td><td rowspan="2">100% General</td><td rowspan="2">100% General</td></tr>
<tr><td>Capital Overhead Allocation</td></tr>
<tr><td>Plant De-Commissioning</td><td>100% Generation</td><td>100% Generation</td><td>100% Generation</td></tr>
<tr><td>Travel and Accommodations</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Business Travel/Accomodations/Meals</td><td rowspan="5">100% General Plant</td><td rowspan="5">61% Generation, 38% Distribution and 1% General Plant [based on positions]</td><td rowspan="5">73% Generation and 27% Distribution [based on positions]</td><td rowspan="5">70% Generation and 30% Distribution</td><td rowspan="5">100% Distribution</td><td rowspan="5">75% Generation, 23% Distribution and 1% General Plant [based on positions]</td></tr>
<tr><td>Training Travel / Accommodations/Meals</td></tr>
<tr><td>Medical Travel / Accommodations/Meals</td></tr>
<tr><td>Relocation Costs</td></tr>
<tr><td>Air Charters</td></tr>
</table>

For some financial information, the Corporation's existing accounting systems do not allow the ideal level of information for a COS study to be tracked. In such circumstances, the Corporation consults with its operations staff to develop estimates of the proportion of expenses spent on generation and distribution related activities. The Corporation believes the estimates are reasonable and can be relied upon for ratemaking purposes.

The Corporation used the following methods to functionalize operating expenses, which are consistent with the 2010/11 Phase II GRA approach:

- **Salaries and Wages:**
  - In order to functionalize salaries and wages for community-based employees, the Corporation reviewed the responsibilities for Plant Operations employees. Most communities (23 out of total 25) have only one Plant Superintendent and one Assistant Operator. The responsibilities of these employees mainly relate to the generation function. However, they are also responsible for some distribution related tasks such as meter reading and customer connection/disconnection. In the 2010/11 GRA the Corporation estimated that distribution related tasks comprise about 30% of a plant operator's time. During the preparation of its 2018/19 GRA the Corporation again reviewed this functionalization and considered that 70% to generation and 30% to distribution split remains a reasonable estimate.
  - All head office departments, with the exception of Territorial Operations (2000) and Engineering (2700), provide general services including

administration, general finance and human resources. Salaries and wages expenses for these departments were functionalized 100% to the general function.

  - The Line Department (2500) provides services directly related to distribution in the Qikiqtaaluk region, and all expenses of this department were functionalized 100% to distribution.
  - For the regional office departments (2100 – Regional Operations) and the remaining head office departments (2000 – Territorial Operations, 2700 – Engineering), the Corporation reviewed each employee position and estimated a breakdown of the employee's responsibilities by each function, consistent with the approach used in the 2010/11 GRA.

- **Supplies and Services:**
  - Expenses for all head office departments, with the exception of Territorial Operations (2000) and Engineering (2700) were functionalized 100% to general, similar to the functionalization of salaries and wages.
  - Expenses for the remaining departments were functionalized based on the review of individual budget codes and descriptions as shown in Table C2.3.
- **Travel and Accommodations:** The expense elements under this category were functionalized following the salaries and wages functionalization ratio for each plant or department.

- **Production Fuel Expense:** Production fuel expense was functionalized 100% to generation, as it is directly used for power generation.
- **Amortization Expense:** Amortization expenses were functionalized based on FERC Codes as outlined in Table C2.1.

C3.0 CLASSIFICATION

Once costs are functionalized, they are classified based on cost drivers between demand, energy, customer and revenue. Revenue related costs include other revenue, which was treated as an offset to the revenue requirement. Where costs can be identified as being specifically incurred by a single customer class, such costs are direct assigned to that customer class. A summary of the classification categories used in the COS study is provided in Table 3.1.

Table C3.1:
QEC COS Study Classification Categories

Description	Category
Coincident Peak Demand	Demand related
Non-Coincident Peak Demand	Demand related
Energy	Energy related
Customer	Customer related
Weighted Customers	Customer related
Revenue Related	Revenue requirement offset
Direct Assignments	Directly assigned

A description of the four main cost classification categories is provided below. Classification methods used for each of the functions in the COS study is provided in the following sections.

<u>Demand-Related</u>

Costs that are driven by the kilowatts of demand each customer imposes on the system are said to be demand-related. Demand-related costs can be considered in at least two sub-categories: system peak demand-related (coincident peak) and customer maximum-demand related (non-coincident peak).

Energy-Related

Energy-related costs are those determined to vary in proportion to the kilowatt-hours consumed by the customer. The principle costs in this category are fuel, and variable operation and maintenance expenses.

Customer-Related

Costs classified as customer-related are those which tend to vary in proportion to the number of customers served. At least two subcategories are generally considered; average number of customers and weighted number of customers. The latter category, weighted customers, is used when the primary cost causation is number of customers, but where certain classes of customers impose proportionately greater costs on the system. One example is meter investment. Every customer has a meter, but general service and industrial meters cost more than residential meters.

Direct Assignment

Costs that can be identified as being incurred to serve a specific customer or class of customers are direct assigned to that customer (for example, streetlighting costs).

C3.1 CLASSIFICATION OF PLANT

Generation Plant

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

When planning generation facilities, the Corporation is primarily concerned with ensuring sufficient capacity is available to meet the community's peak. Therefore demand is the primary cost driver for generation assets. Consistent with this cost driver, generation plant assets were classified as 100% demand related with the exception of fuel holders, which were classified as 100% energy related.

This classification method is consistent with Corporation's 2010/11 GRA approach, and most other utilities in Canada that operate isolated diesel plants. Yukon Energy Corporation, ATCO Electric Yukon, Northwest Territories Power Corporation and Northland Utilities (NWT) Ltd all classify the majority of diesel generation plant 100% to demand.

Distribution Plant

Investment in distribution plant is driven by the number and location of customers and the peak demand imposed by those customers. Investment in distribution plant does not vary with the consumption of energy. Therefore distribution plant is classified to demand and customer. This is consistent with the practice followed by other Canadian northern utilities, as well as the classification of distribution plant in the National Association of Regulatory Utility Commissioners (NARUC) Manual.

The classification factors for poles, towers and fixtures, overhead conductors and underground conduits, and line transformers are based on the classification factors used by the Northwest Territories Power Corporation (NTPC) in their most recent general rate application (2016/19 GRA).

The Corporation's distribution plant facilities include the following assets:

- **Land and Land Rights, Structures & Improvements, Station Equipment, Storage Battery Equipment:** These assets are sized and built to meet system demand requirements and their size is not affected by the number of customers to be served. Therefore these assets have been classified as 100% demand-related.
- **Services, Meters and Metering Equipment:** These assets are designed to meet the needs of specific customers and their costs are dependent on the number and type of customers to be served. Therefore these assets were classified as 100% customer-related.
- **Street Lights:** These assets were directly assigned to the streetlight customer class.
- **Poles, Towers and Fixtures:** Investment in these assets is driven partly by the demand placed on the system and partly by the number of customers to be served. These assets were classified as 45% demand related and 55% customer related based on NTPC's 2016/19 Phase II rate application. The discussion on determining these classification factors is provided in Section 10.4.2.
- **Overhead Conductors / Underground Conduits:** Investment in these assets is primarily driven by the number of customers to be served, but the investment must also consider the demand of the customer. These assets were classified as 50%

demand related and 50% customer related based on NTPC's 2016/19 Phase II rate application. The discussion on determining these classification factors is provided in Section 10.4.2.

- **Line Transformers:** Investment in these assets is primarily driven by the demand imposed on the system. However some consideration is also given to the number of customers to be served. These assets were classified as 71% demand related and 29% customer related based on NTPC's 2016/19 Phase II rate application. The discussion on determining these classification factors is provided in Section 10.4.2.

Classification of distribution plant facilities is summarized in Table 3.2.

Table C3.2:
Classification of Distribution Plant

	Customer		Demand		Direct Assigned	Basis
	Actual	Weighted	CP	NCP		
Distribution Plant						
Land & Rights, Sub Equipments (FERC 360-363)	0%			100%		Reviewed by URRC in Report 2012-01
Poles, Towers and Fixtures (FERC 364)	55%			45%		Based on NTPC's 2016/19 GRA
O/H Conductors (FERC 365)	50%			50%		Based on NTPC's 2016/19 GRA
Underground Conduits (FERC 366-367)	50%			50%		Based on NTPC's 2016/19 GRA
Transformers (FERC 368) - Weighted		29%		71%		Based on NTPC's 2016/19 GRA
Services and Meters (FERC 369-371) - Weighted		100%				Based on NTPC's 2016/19 GRA
Street Lights (FERC 373) - Direct Assigned					100%	Reviewed by URRC in Report 2012-01

<u>General Plant</u>

General plant consists of a variety of facilities used to administer generation, distribution and customer service functions of the utility. General plant costs do not vary materially with increases in the number of customer, community demand or energy consumed, but are required to provide all services to customers. Therefore, the Corporation classified general plant assets into customer, demand, and energy related costs based on the proportion of total generation and distribution assets classified to demand, energy and customer categories.

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.
  - General plant related – based on the proportion of total general assets classified to customer, demand, and energy categories.
- **Working Capital:**
  - Cash – based on the proportion of total general plant assets classified to customer, demand, and energy categories.
  - Materials and Supplies – based on the proportion of total general plant assets classified to customer, demand, and energy categories.
  - Fuel – 100% to energy.

C3.2 CLASSIFICATION OF EXPENSES

Generation Plant

Generation plant expenses include production fuel and non-fuel related operating and maintenance expenses.

Production fuel is a variable cost that is incurred in direct proportion to the amount of energy consumed by each customer class. Therefore fuel expenses were classified as 100% energy-related.

Non-fuel operating and maintenance expenses include both variable costs that are incurred in relation to the consumption of energy and non-variable cost that are related to maintaining assets in safe, reliable working order to meet the community's capacity requirements. Therefore the Corporation classified non-fuel operating and maintenance expenses 50% to demand and 50% to energy. This classification is consistent with Corporation's 2010/11 GRA and the current practice in other Northern utilities in Canada.

Distribution Plant

In order to classify distribution plant expenses, the Corporation calculated a classification ratio based on the total gross distribution plant classified to demand related and customer related costs. This ratio was used to classify distribution plant expenses, except the billing and customer accounting related expenses which were classified to the weighted customer category based on the URRC's recommendations in its Report 2012-01[2] to the Minister.

General Plant

General plant expenses were classified using the same classification ratios calculated for the classification of general plant assets, i.e. based on the proportion of total generation and distribution assets classified to demand, energy and customer categories.

Table 3.3 provides summary of classification of expenses by function.

Table C3.3:
Classification of Expenses by Function

	Customer		Demand		Energy	Direct Assigned
	Actual	Weighted	CP	NCP		
Production Fuel	0%		0%		100%	
Non-Fuel O&M	0%		50%		50%	
Distribution	Based on Total Distribution Plant Classified to Customer / Demand					
General Plant	Based on Classification of General Plant					

Other expense categories were classified into customer, demand, and energy related as follows:

[2] In its Report 2012-01, the URRC recommended that QEC classify meter reading, billing and customer accounting related expenses to the customer category. The Billing and Revenue department was merged with the General Finance department following the 2010/11 GRA. As a separate expense code for billing and customer accounting related expenses is no longer available, the Corporation prorated these costs based on the information available from the 2010/11 GRA (URRC-QEC-1-7c, Attachment 1).

- **Amortization Expense:**
    - 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.
    - General plant related – based on the proportion of total general assets classified to customer, demand, and energy categories.
- **Other Revenue:** Other revenue was classified as 100% revenue related consistent with the URRC's recommendations in its Report 2012-01[3] to the Minister.

[3] See Section 10.4.4 of the Application.

C4.0 ALLOCATION

This chapter describes the methods used to develop the allocation factors used in the Corporation's COS study. The allocation factors were developed based on information from customer billing records, the Corporation's load forecast, and information from electric utilities with similar types of customer classes and operating environments.

C4.1 DEMAND ALLOCATION FACTORS

In the development of demand allocation factors for each customer group, two steps are required.

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

The COS study uses two demand allocators:

- Coincident peak: is the peak for a customer class at the time of the system peak.
- Non-coincident peak: is the annual peak for a customer class in the year.

Generation demand-related costs are generally considered to be related to coincident demands (i.e., customer group peaks 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 the Corporation allocated generation demand-related costs based on the class's share of the total plant coincident peak (CP). This method is consistent with 2010/11 GRA and industry practice for other utilities in Northern Canada.

In contrast, line transformers, poles and fixtures and other distribution system components are sized to meet the maximum demands of 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 the Corporation requires estimates of the customer class load factor and coincidence factor in order to estimate the coincident and non-coincident peaks for each class. The Corporation did not undertake load research on individual customer classes across communities in Nunavut because it is not economically feasible. In developing estimates of customer class load factor and coincidence factors for the 2010/11 GRA, the Corporation reviewed the data developed by other utilities. These factors were accepted by the URRC in the Report 2012-01.[4] For the current COS study the Corporation similarly used customer class load factor and coincidence factors from NTPC's 2016/19 Phase II rate application.

A summary of the load factors and coincidence factors used by the Corporation in the COS analysis is provided in Table 4.1.

[4] URRC's report on QEC's 2010/11 Phase II GRA, 2012-01 dated from January 27, 2012, p.23.

Table C4.1:
QEC's Recommended Load Parameters

Customer Class	NCP Load Factor	Coincidence Factor
Domestic	43.8%	86.8%
Commercial	55.0%	83.2%
Streetlights	47.3%	100.0%

C4.1.1 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 2018/19 test year load forecast by customer class.

C4.1.2 CUSTOMER ALLOCATION FACTORS

Customer-related costs were allocated to customer classes based on number of customers and weighted number of customers.

Common industry practice is to allocate customer-related costs that do not vary with the type of customers or its consumption of electricity on the basis of actual number of customers in each class (e.g., poles and fixtures).

A weighted number of customers is typically used for costs that vary with the type of customer or its consumption of electricity. For example, metering device costs are different for commercial customers than domestic customers. The Corporation used weighted number of customers to allocate services, meters and line transformer assets, billing and customer accounting related expenses. In the 2010/11 GRA the Corporation assumed a customer weighting of 1.0 for domestic and 3.0 for commercial customers.

In its Report 2012-01 the URRC recommended to the Minister that QEC conduct a study of the appropriate customer weighting factors for domestic, commercial, street and yard lighting customers at the time of the next COS study.[5]

At the time of the 2014/15 GRA preparation, the Corporation performed a review of the customer weighting factors in accordance with the above recommendation. The analysis of transformer costs, which account for approximately 40% of the distribution plant allocated on weighted customer basis, suggest that, in general one transformer is used to serve six domestic customers, or two commercial customers. With respect to the meter costs, which account for approximately 7% of the distribution plant allocated on weighted customer basis, the review suggests that, in general, QEC's commercial meter devices are approximately 7 times more expensive than residential meter devices.

The Corporation also reviewed the service weighting analysis performed by NUL-NWT as part of its 2011-2013 GRA, and notes that on average service cost is approximately twice as much for commercial customer as compared to residential customers, which was reviewed and accepted by the Northwest Territories PUB in Decision 5-2012.[6] Taking into account the similarity of QEC's and NUL-NWT's customer base the Corporation considers it is reasonable to rely on service cost weighting factors determined by NUL-NWT. Service

[5] URRC's report on QEC's 2010/11 Phase II GRA, 2012-01 dated from January 27, 2012, p.20.
[6] NWT PUB Decision 5-2012, p. 38-41.

costs account for approximately 53% of the distribution plant allocated on weighted customer basis.

Based on the above review, the Corporation determined the updated weighting factors for domestic and commercial customers as shown in Table 4.2.

Table C4.2:
Calculation of Customer Weighting Factor

	Cost Ratio by Customer Category			Weighted
	Transformer	Meter	Services	Average
Domestic	1	1	1	1
Commercial	3	7	2	3
Share in Allocated Distr. Plant	40%	7%	53%	

The updated weighting factor suggests that the weighting factor of 3 for commercial and 1 for domestic is still appropriate and the Corporation used these weighting factors in its 2018/19 GRA COS.

The Corporation considers customer related costs associated with streetlighting customers to be similar to those of domestic customers, and as such streetlighting customers were assigned a customer weighting factor of 1 relative to domestic customers.

C4.1.3 REVENUE OFFSET ALLOCATION FACTORS

The Corporation applied other revenue (revenue from non-electrical sales) as an offset to the Corporation's revenue requirement. Other revenue was allocated to customer classes proportionate to their share of total 2018/19 test year forecast revenue at existing or pre-2018/19 GRA rates.

APPENDIX D

COST-OF-SERVICE STUDY SCHEDULES

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Territory-Wide Cost of Service

Exhibit 1 - Functionalization and Classification of Rate Base

			Demand Related		**Energy**	**Customer Related**		**Revenue**	**Direct**
		$000	Coin. Peak	NC Peak	**Related**	Actual	Weighted	**Related**	**Assign.**
	Plant Description	**Total**	*CP*	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*
	Generation Plant								
340	Land and Land Rights	$1,229.5	$1,229.5	$.0	$.0	$.0	$.0	$.0	$.0
341	Structures & Improvements	$94,897.4	$94,897.4	$.0	$.0	$.0	$.0	$.0	$.0
342	Fuel Holders, Prod., & Access.	$22,723.4	$.0	$.0	$22,723.4	$.0	$.0	$.0	$.0
343	Prime Movers	$89,468.9	$89,468.9	$.0	$.0	$.0	$.0	$.0	$.0
344	Generators	$44,784.4	$44,784.4	$.0	$.0	$.0	$.0	$.0	$.0
345	Accessory Electric Equip.	$22,478.3	$22,478.3	$.0	$.0	$.0	$.0	$.0	$.0
346	Misc. Power Plant Equip.	$25,095.4	$25,095.4	$.0	$.0	$.0	$.0	$.0	$.0
121	Wind Energy Production	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
131	Heat Recovery Systems	$175.6	$175.6	$.0	$.0	$.0	$.0	$.0	$.0
	Insurance Proceeds	-$22,714.1	-$22,714.1	$.0	$.0	$.0	$.0	$.0	$.0
	Total Generation Plant	$278,138.9	$255,415.5	$.0	$22,723.4	$.0	$.0	$.0	$.0
	Distribution Plant								
360	Land and Land Rights	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
361	Structures & Improvements	$8,465.1	$.0	$8,465.1	$.0	$.0	$.0	$.0	$.0
362	Station Equipment	$7,430.5	$.0	$7,430.5	$.0	$.0	$.0	$.0	$.0
363	Storage Battery Equip.	$10.0	$.0	$10.0	$.0	$.0	$.0	$.0	$.0
364	Poles & Fixtures	$14,972.5	$.0	$6,737.6	$.0	$8,234.9	$.0	$.0	$.0
365	OH Conductors & Devices	$5,008.4	$.0	$2,504.2	$.0	$2,504.2	$.0	$.0	$.0
366	Underground Conduit	$40.5	$.0	$20.3	$.0	$20.3	$.0	$.0	$.0
367	Underground Conduct. & Devices	$125.9	$.0	$62.9	$.0	$62.9	$.0	$.0	$.0
368	Line Transformers	$6,490.5	$.0	$4,608.3	$.0	$.0	$1,882.3	$.0	$.0
369	Services	$2,050.4	$.0	$.0	$.0	$.0	$2,050.4	$.0	$.0
370	Meters	$19.8	$.0	$.0	$.0	$.0	$19.8	$.0	$.0
371	Install. on Cust. Premises	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
372	Leased Prop. on Cust. Prem.	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
373	Street Lighting	$1,547.8	$.0	$.0	$.0	$.0	$.0	$.0	$1,547.8
	Total Distribution Plant	$46,161.4	$.0	$29,838.9	$.0	$10,822.3	$3,952.4	$.0	$1,547.8
	Total Plant before General Plant	$324,300.2	$255,415.5	$29,838.9	$22,723.4	$10,822.3	$3,952.4	$.0	$1,547.8

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Territory-Wide Cost of Service
Exhibit 1 - Functionalization and Classification of Rate Base

		Basis of Classification							
	Plant Description	*CP*	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*	
	Generation Plant								
340	Land and Land Rights	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
341	Structures & Improvements	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
342	Fuel Holders, Prod., & Access.	0.000	0.000	1.000	0.000	0.000	0.000	0.000	100% energy
343	Prime Movers	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
344	Generators	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
345	Accessory Electric Equip.	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
346	Misc. Power Plant Equip.	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
121	Wind Energy Production	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
131	Heat Recovery Systems	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
	Insurance Proceeds	1.000	0.000	0.000	0.000	0.000	0.000	0.000	100% demand (CP)
	Total Generation Plant	0.918	0.000	0.082	0.000	0.000	0.000	0.000	
	Distribution Plant								
360	Land and Land Rights	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
361	Structures & Improvements	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
362	Station Equipment	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
363	Storage Battery Equip.	0.000	1.000	0.000	0.000	0.000	0.000	0.000	100% demand (NCP)
364	Poles & Fixtures	0.000	0.450	0.000	0.550	0.000	0.000	0.000	45% demand and 55% customer
365	OH Conductors & Devices	0.000	0.500	0.000	0.500	0.000	0.000	0.000	50% demand and 50% customer
366	Underground Conduit	0.000	0.500	0.000	0.500	0.000	0.000	0.000	50% demand and 50% customer
367	Undergrd Conduct. & Devices	0.000	0.500	0.000	0.500	0.000	0.000	0.000	50% demand and 50% customer
368	Line Transformers	0.000	0.710	0.000	0.000	0.290	0.000	0.000	71% demand and 29% customer (weighted)
369	Services	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
370	Meters	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
371	Install. on Cust. Premises	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
372	Leased Prop. on Cust. Prem.	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% customer (weighted)
373	Street Lighting	0.000	0.000	0.000	0.000	0.000	0.000	1.000	100% direct assigned
		0.000	0.646	0.000	0.234	0.086	0.000	0.034	

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Territory-Wide Cost of Service
Exhibit 1 - Functionalization and Classification of Rate Base

		Demand Related		Energy	Customer Related		Revenue	Direct
	$000	Coin. Peak	NC Peak	Related	Actual	Weighted	Related	Assign.
Plant Description	**Total**	*CP*	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*
General Plant								
383 Computer Software	$1,681.5	$1,324.3	$154.7	$117.8	$56.1	$20.5	$.0	$8.0
389 Land and Land Rights	$7.1	$5.6	$.7	$.5	$.2	$.1	$.0	$.0
390 Structures & Improvements	$19,109.5	$15,050.4	$1,758.3	$1,339.0	$637.7	$232.9	$.0	$91.2
391 Office Furniture & Equip.	$270.1	$212.7	$24.8	$18.9	$9.0	$3.3	$.0	$1.3
392 Transportation Equip.	$8,004.8	$6,304.5	$736.5	$560.9	$267.1	$97.6	$.0	$38.2
393 Stores Equip.	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
394 Tools, Shop, & Garage Equip.	$423.9	$333.8	$39.0	$29.7	$14.1	$5.2	$.0	$2.0
395 Laboratory Equip.	$.0	$.0	$.0	$.0	$.0	$.0	$.0	$.0
396 Power Operated Equip.	$229.4	$180.7	$21.1	$16.1	$7.7	$2.8	$.0	$1.1
397 Communication Equip.	$303.3	$238.8	$27.9	$21.2	$10.1	$3.7	$.0	$1.4
398 Misc. Equip.	$1,123.5	$884.9	$103.4	$78.7	$37.5	$13.7	$.0	$5.4
399 Other Tangible Property	$2,785.6	$2,193.9	$256.3	$195.2	$93.0	$34.0	$.0	$13.3
Total General Plant	$33,938.6	$26,729.7	$3,122.7	$2,378.0	$1,132.6	$413.6	$.0	$162.0
Total Plant in Service	$358,238.8	$282,145.1	$32,961.6	$25,101.4	$11,954.9	$4,366.1	$.0	$1,709.7
Less: Accum. Amortization								
Generation Plant	$109,696.9	$100,734.9	$.0	$8,962.0	$.0	$.0	$.0	$.0
Distribution Plant	$12,778.9	$.0	$8,260.4	$.0	$2,996.0	$1,094.2	$.0	$428.5
General Plant	$13,815.7	$10,881.1	$1,271.2	$968.1	$461.0	$168.4	$.0	$65.9
Total Accum. Amortization	$136,291.5	$111,615.9	$9,531.5	$9,930.1	$3,457.0	$1,262.5	$.0	$494.4
Add: Working Capital								
Cash	$4,881.3	$3,844.4	$449.1	$342.0	$162.9	$59.5	$.0	$23.3
Materials & Supplies	$14,427.6	$11,363.0	$1,327.5	$1,010.9	$481.5	$175.8	$.0	$68.9
Fuel	$8,017.5	$.0	$.0	$8,017.5	$.0	$.0	$.0	$.0
Total Working Capital	$27,326.4	$15,207.4	$1,776.6	$9,370.5	$644.4	$235.3	$.0	$92.2
Total Rate Base	$249,273.7	$185,736.6	$25,206.6	$24,541.9	$9,142.2	$3,338.9	$.0	$1,307.5

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Territory-Wide Cost of Service
Exhibit 1 - Functionalization and Classification of Rate Base

		Basis of Classification							
		CP	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*	
	General Plant								
389	Land and Land Rights	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
390	Structures & Improvements	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
390	Structures & Improvements	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
391	Office Furniture & Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
392	Transportation Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
393	Stores Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
394	Tools, Shop, & Garage Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
395	Laboratory Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
396	Power Operated Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
397	Communication Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
398	Misc. Equip.	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
399	Other Tangible Property	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As Generation and Distribution Plants
	Total General Plant	0.788	0.092	0.070	0.033	0.012	0.000	0.005	
	Less: Accum. Amortization								
	Generation Plant	0.918	0.000	0.082	0.000	0.000	0.000	0.000	As Generation Plant
	Distribution Plant	0.000	0.646	0.000	0.234	0.086	0.000	0.034	As Distribution Plant
	General Plant	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As General Plant
	Add: Working Capital								
	Cash	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As General Plant
	Materials & Supplies	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As General Plant
	Fuel	0.000	0.000	1.000	0.000	0.000	0.000	0.000	100% Energy
	Total Working Capital								

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Territory-Wide Cost of Service
Exhibit 2 - Funct. & Classification of Net Revenue Requirements

		Demand Related		**Energy**	**Customer Related**		**Revenue**	**Direct**
	$000	Coin. Peak	NC Peak	**Related**	Actual	Weighted	**Related**	**Assign.**
Expense Description	**Total**	*CP*	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*
Generation Expense								
Non-Fuel Generation O&M	$22,652.9	$11,326.4	$.0	$11,326.4	$.0	$.0	$.0	$.0
Production Fuel	$48,819.9	$.0	$.0	$48,819.9	$.0	$.0	$.0	$.0
Total Generation Expense	$71,472.8	$11,326.4	$.0	$60,146.3	$.0	$.0	$.0	$.0
Distribution Expense								
Distribution O&M	$9,905.5	$.0	$6,402.9	$.0	$2,322.3	$848.1	$.0	$332.1
Total Distribution	$9,905.5	$.0	$6,402.9	$.0	$2,322.3	$848.1	$.0	$332.1
Total O&M before Admin & Gen.	$81,378.2	$11,326.4	$6,402.9	$60,146.3	$2,322.3	$848.1	$.0	$332.1
Admin. & General Expense								
General Plant O&M [excl. billing and cust a	$25,656.8	$20,207.0	$2,360.7	$1,797.7	$856.2	$312.7	$.0	$122.4
Billing and Customer Accounting Related	$1,958.3	$.0	$.0	$.0	$.0	$1,958.3	$.0	$.0
Total A&G Expense	$27,615.1	$20,207.0	$2,360.7	$1,797.7	$856.2	$2,271.0	$.0	$122.4
Total Oper. & Maint. Expense	$108,993.3	$31,533.5	$8,763.6	$61,944.1	$3,178.5	$3,119.1	$.0	$454.6
Net Amortization Expense:								
Generation Amortization	$8,271.6	$7,595.9	$.0	$675.8	$.0	$.0	$.0	$.0
Distribution Amortization	$1,002.4	$.0	$648.0	$.0	$235.0	$85.8	$.0	$33.6
General Amortization	$1,931.1	$1,520.9	$177.7	$135.3	$64.4	$23.5	$.0	$9.2
Total Amort. Expense	$11,205.2	$9,116.8	$825.7	$811.1	$299.5	$109.4	$.0	$42.8
Total Rev. Requirement before Return	$120,198.5	$40,650.2	$9,589.3	$62,755.2	$3,477.9	$3,228.5	$.0	$497.4
Less: Other Revenue	$2,547.7	$.0	$.0	$.0	$.0	$.0	$2,547.7	$.0
Net Rev. Requirement before Return	$117,650.8	$40,650.2	$9,589.3	$62,755.2	$3,477.9	$3,228.5	-$2,547.7	$497.4
Return on Rate Base	$13,848.9	$10,319.0	$1,400.4	$1,363.5	$507.9	$185.5	$.0	$72.6
Total Net Rev. Requirement	$131,499.7	$50,969.2	$10,989.7	$64,118.6	$3,985.9	$3,414.0	-$2,547.7	$570.0

2018/19 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 2 - Funct. & Classification of Net Revenue Requirements

	Basis for Classification							
	CP	*NCP*	*E*	*CUST-1*	*CUST-2*	*RR*	*DA*	
Generation Expense								
Non-Fuel O&M	0.500	0.000	0.500	0.000	0.000	0.000	0.000	50% demand and 50% energy
Production Fuel	0.000	0.000	1.000	0.000	0.000	0.000	0.000	100% energy
Total Generation Expense								
Distribution Expense								
Distribution O&M	0.000	0.646	0.000	0.234	0.086	0.000	0.034	As Distribution Plant
Total Distribution								
Total O&M before Admin & Gen.								
Admin. & General Expense								
Vehicles and Equipment	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As General Plant
	0.000	0.000	0.000	0.000	1.000	0.000	0.000	100% to weighted customer
Total A&G Expense								
Total Oper. & Maint. Expense								
Net Amortization Expense:								
Generation Amortization	0.918	0.000	0.082	0.000	0.000	0.000	0.000	As Generation Plant
Distribution Amortization	0.000	0.646	0.000	0.234	0.086	0.000	0.034	As Distribution Plant
General Amortization	0.788	0.092	0.070	0.033	0.012	0.000	0.005	As General Plant
Total Amort. Expense	0.814	0.074	0.072	0.027	0.010	0.000	0.004	
Total Rev. Requirement before Return								
Total Other Revenue	0.000	0.000	0.000	0.000	0.000	1.000	0.000	
Net Rev. Req. before Return	0.346	0.082	0.533	0.030	0.027	(0.022)	0.004	
Return on Rate Base	0.745	0.101	0.098	0.037	0.013	0.000	0.005	
Total Net Rev. Requirement	0.388	0.084	0.488	0.030	0.026	(0.019)	0.004	

2018/19 General Rate Application
Territory-Wide Cost of Service
Exhibit 3 - Analysis of Load Data

Appendix D

Hours in Year	8,760

Domestic	Total	Commercial		Street Lighting	
kWh Sales at the Meter	67,762,829	kWh Sales at the Meter	109,139,259	kWh Sales at the Meter	1,948,584
Load Factor	44%	Load Factor	55%	Load Factor	47%
Individ. Noncoincident Peak (NCP)(kW)	17,661	Individ. Noncoincident Peak (NCP)(kW)	22,652	Individ. Noncoincident Peak (NCP)(kW)	470
Group Coincidence Factor	100%	Group Coincidence Factor	100%	Group Coincidence Factor	100%
NCP at the Meter for the Group (kW)	17,661	NCP at the Meter for the Group (kW)	22,652	NCP at the Meter for the Group (kW)	470
System Coincidence Factor	87%	System Coincidence Factor	83%	System Coincidence Factor	100%
Coincident Peak (CP) at Meter (kW)	15,330	Coincident Peak (CP) at Meter (kW)	18,847	Coincident Peak (CP) at Meter (kW)	470

2018/19 General Rate Application
Territory-Wide Cost of Service
Exhibit 4 - Demand Allocation Factor

	Coincident Peak Alloc. Factor	*% of Total*	*Noncoincident Peak Alloc. Factor*	*% of Total*
Domestic	15,330	44.2%	17,661	43.3%
Commercial	18,847	54.4%	22,652	55.5%
Street Lighting	470	1.4%	470	1.2%
Total	34,647	100%	40,784	100%
Allocation Factor		*CP*		*NCP*

Method of CP demand allocation:
the peak responsibility method

2018/19 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 5 - Energy Allocation Factor

	Energy Alloc. Factor (kWh)	*% of Total*
Domestic	67,762,829	37.9%
Commercial	109,139,259	61.0%
Street Lighting	1,948,584	1.1%
Total	178,850,672	100%
Allocation Factor		*E*

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Exhibit 6 - Customer Allocation Factor

	Actual Customers				
	Total Customers	*% of Total*	Weighting Factor	Weighted Customers	*% of Total*
Domestic	11,812	77.9%	1.0	11,812	54.2%
Commercial	3,307	21.8%	3.0	9,921	45.5%
Street Lighting	51	0.3%	1.0	51	0.2%
Total	15,170	100%		21,784	100%
Allocation Factor		*CUST-1*			*CUST-2*

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Exhibit 7 - Revenue Allocation Factor

$000	*Existing Rate Revenues*	*% of Total*
Domestic	$54,192.0	40.9%
Commercial	$76,422.1	57.7%
Street Lighting	$1,749.4	1.3%
Total	$132,363.4	100%
Allocation Factor		*RR*

2018/19 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 8 - Allocation of Plant in Service (Rate Base)

$000	Total Plant	Domestic	Commercial	Street Lighting	Basis of Allocation
DEMAND RELATED					
Coincident Peak	$185,736.6	$82,180.4	$101,035.2	$2,521.1	CP
Noncoincident Peak	$25,206.6	$10,915.5	$14,000.5	$290.7	NCP
Total Demand	$210,943.3	$93,095.8	$115,035.7	$2,811.8	
ENERGY RELATED	$24,541.9	$9,298.4	$14,976.1	$267.4	E
CUSTOMER RELATED					
Actual	$9,142.2	$7,118.5	$1,993.0	$30.7	CUS-1
Weighted	$3,338.9	$1,810.4	$1,520.6	$7.8	CUS-2
Total Customer	$12,481.1	$8,928.9	$3,513.6	$38.6	
REVENUE RELATED	$.0	$.0	$.0	$.0	RR
DIRECT ASSIGNMENT	$1,307.5	$.0	$.0	$1,307.5	DA
Total Plant in Service	$249,273.7	$111,323.2	$133,525.4	$4,425.2	

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Territory-Wide Cost of Service
Exhibit 9 - Allocation of Net Revenue Requirements

$000	Total Net Rev. Req.	Domestic	Commercial	Street Lighting	Basis of Allocation
DEMAND RELATED					
Coincident Peak	$40,650.2	$17,986.0	$22,112.5	$551.8	CP
Noncoincident Peak	$9,589.3	$4,152.5	$5,326.2	$110.6	NCP
Total Demand	$50,239.5	$22,138.5	$27,438.7	$662.3	
ENERGY RELATED	$62,755.2	$23,776.6	$38,294.8	$683.7	E
CUSTOMER RELATED					
Actual	$3,477.9	$2,708.1	$758.2	$11.7	CUS-1
Weighted	$3,228.5	$1,750.6	$1,470.4	$7.6	CUS-2
Total Customer	$6,706.4	$4,458.6	$2,228.5	$19.3	
REVENUE RELATED	-$2,547.7	-$1,043.1	-$1,470.9	-$33.7	RR
DIRECT ASSIGNMENT	$497.4	$.0	$.0	$497.4	DA
Total Net Rev. Req.	$117,650.8	$49,330.7	$66,491.1	$1,829.0	

2018/19 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 10 - Summary

$000	Total	Domestic	Commercial	Street Lighting
Present Rate Revenues	$132,363.4	$54,192.0	$76,422.1	$1,749.4
Allocated Rev. Req.	$117,650.8	$49,330.7	$66,491.1	$1,829.0
Rate Base	$249,273.7	$111,323.2	$133,525.4	$4,425.2
Allowed Rate of Return	5.6%	5.6%	5.6%	5.6%
Allowed Return	$13,848.9	$6,184.8	$7,418.3	$245.8
Required Rate Revenues	$131,499.7	$55,515.5	$73,909.3	$2,074.9
Balance	$863.7	-$1,323.5	$2,512.7	-$325.5
RCC ratio		97.6%	103.4%	84.3%

2018/19 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 11 - Average Unit Costs

		Domestic	Commercial	Street Lighting
DEMAND - $/kW		$0.00	$68.15	$0.00
ENERGY - cents/kWh		74.61	34.50	105.38
CUSTOMER - $/Cust/Month		$34.96	$61.08	$34.96
Basic Data:				
Annual Kwh		-	496,425	-
Annual kWh		67,762,829	109,139,259	1,948,584
Number of Customers		11,812	3,307	51
Revenue Check ($000):				
Demand	$33,829.7	$.0	$33,829.7	$.0
Energy	$90,270.2	$50,560.8	$37,655.9	$2,053.5
Customer	$7,399.8	$4,954.7	$2,423.7	$21.4
Total	$131,499.7	$55,515.5	$73,909.3	$2,074.9

2018/19 General Rate Application **Appendix D**
Territory-Wide Cost of Service
Exhibit 12 - Average Unit Costs at $18/month customer charge and $8/kW demand charge

		Domestic	Commercial	Street Lighting
DEMAND - $/kW		$0.00	$8.00	$0.00
ENERGY - cents/kWh		78.16	64.08	106.48
CUSTOMER - $/Cust/Month		$18.00	$0.00	$0.00
Revenue Check ($000):				
Demand	$3,971.4	$.0	$3,971.4	$.0
Energy	$124,977.0	$52,964.1	$69,938.0	$2,074.9
Customer	$2,551.3	$2,551.3	$.0	$.0
Total	$131,499.7	$55,515.5	$73,909.3	$2,074.9

APPENDIX E

MINISTER'S INSTRUCTION DATED JANUARY 29, 2014

UTILITY RATES REVIEW COUNCIL ACT

NUNAVUT

INSTRUCTION

I, PAUL OKALIK, Minister Responsible for Qulliq Energy Corporation, after careful consideration with the Executive Council

HEREBY INSTRUCT THE CORPORATION AS FOLLOWS:

1. To retract the instruction to move towards a territorial rate that was issued to QEC by a letter of instruction on February 20, 2012 from a former Minister responsible for QEC.

2. To remove Phase II of QEC's 2014/15 General Rate Application, currently under review by the Utility Rates Review Council, and seek only implementation of Phase I component of the Application by way of an equal percentage across-the-board increase to current rates. All customers would see the same percentage increase in their current rates.

3. To file a Phase II General Rate Application that provides several Cost of Service study options for consideration in its next General Rate Application, that is expected to be submitted by 2018.

DATED AT IQALUIT, IN THE TERRITORY OF NUNAVUT
THIS 29TH DAY OF JANUARY, 2014

Paul Okalik
Minister Responsible for Qulliq Energy Corporation

INSTRUCTION TO QULLIQ ENERGY CORPORATION
Utility Rates Review Council Act
January 29, 2014
The Honourable Paul Okalik, Minister Responsible for Qulliq Energy Corporation

APPENDIX F

GLOSSARY OF TERMS

Amortization

Allocation of the cost of an asset over its useful life, reflecting a reduction in the value of an asset with the passage of time, due in particular to wear and tear.

Capacity

The load at which a generation unit, generation station, or other electrical apparatus is rated either by the user or by the manufacturer.

Consumer Price Index (CPI)

A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Commercial

Customer classification for service other than domestic or street lighting.

Corporation

Qulliq Energy Corporation

Cost of Service

The total cost to the Corporation of providing energy and related utility services to its customers. Includes the cost of invested capital as well as operational costs.

Customer

Individual or entity that takes service from the utility. Similar customers are grouped into customer classes. Customer classes are usually differentiated from each other in terms of the level and type of service they require from the utility.

Customer Class

A distinction between users of electrical energy.

Demand

The rate at which electric energy is delivered to or by a system, part of a system or a piece of equipment; expressed in kilowatts, kilovolt-amperes, or other suitable unit at a given instant or averages over any designated period of time. The primary source of demand is the power-consuming equipment of the customers.

Demand Side Management (DSM)

Techniques designed to be used by the customer to reduce their consumption of energy.

Distribution

The act or process of distributing electric energy from convenient points on the transmission or bulk power system to the consumers.

Domestic

Single family residences or an individual apartment where electrical service is provided through one meter, provided that the residence or apartment is not used for commercial purposes.

Efficiency

Engine efficiency; the amount of kilowatt-hours produced per litre of fuel.

Energy

a) Electricity;

b) Heat that is supplied through a district heating system by hot water, hot air or steam; manufactured gas, liquefied petroleum gas, natural gas, oil or any other combustible material which is supplied through a pipeline or any other distribution system directly to a customer; or

c) Any prescribed matter pursuant to a regulation under the Qulliq Energy Act.

Energy Consumption

Use of electrical energy over time, typically measured in kilowatt-hours (kWh).

FERC

Federal Energy Regulatory Commission

Fixed Asset

Tangible property used in the operations of regulated business, but not expected to be consumed or converted into cash in the ordinary course of business.

Generation

This term refers to the act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kWh.

Gross Plant in Service

Represents the accounting cost of all regulated assets current used in ordinary course of business.

Heating Degree Day (HDD)

A unit measuring the extent to which an outdoor dry-bulb temperature falls below an assumed base (18°C). One HDD is counted for each degree of deficiency below the assumed base, for each calendar day on which such a deficiency occurs.

Kilowatt (kW)

The measure of electrical capacity required by the customer at any instantaneous moment. One kilowatt equals 1,000 watts. One megawatt (MW) equals 1,000 kWs.

Kilowatt-hour (kWh)

Basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Load

The amount of electric power delivered or required at any specific point or points on a system. Load originates primarily at the power-consuming equipment of customers.

Load Forecast

An estimate of electrical demand or energy consumption at some future time.

Losses

Refers to the energy that is lost through distribution and transformation.

Maintenance Expense

Direct and indirect expenses including labour, material and others incurred for preserving the operation efficiency or physical condition of the utility plant used for power production, transmission and distribution of energy, and administrative and general operations.

O&M

Operating and Maintenance

Operating Expenses

Direct and indirect expenses, including labour, materials and others, incurred in the production of electricity.

Outage

The period during which a generation unit, distribution line, or other facility is out of service.

Plant

A facility or facilities for the generation, transformation, distribution, delivery, supply or control of energy or for the distribution, delivery or supply of water and sewerage services and includes the site of the facility or facilities, and all land, water, rights to use water, buildings, works, machinery, installations, materials, transmission lines, distribution lines, pipelines, furnishings and equipment, plant in construction, stores and supplies acquired, constructed or used or adapted for or in connection with the facility or facilities.

Power

The rate of generating, transferring, or use of electric energy, with respect to time, usually expressed in kilowatts (kW).

Rate Base

The property of the Corporation used or required to be used to provide service to the public within Nunavut.

Rates [electricity]

The prices at which electricity sold to the customers.

Residual Heating System

Residual heat recovery involves capturing some of the excess heat from the diesel engines.

Revenue Requirement

The revenue level necessary to meet the cost of providing service to the utility's customer.

Station Service

The electric energy used by the Corporation in the course of business.

URRC

Utility Rates Review Council