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UTILITY RATES REVIEW COUNCIL OF NUNAVUT
IGLUIN AULATJUTITIGUN AKITUTILAANGINNUT KATIMAYIIT NUNAVUNMI
CONSEIL D'EXAMEN DES TAUX DES ENTREPRISES DE SERVICES DU NUNAVUT

March 26, 2018

Hon. Jeannie Hakongak Ehaloak
Minister responsible for
the Qulliq Energy Corporation (QEC)
Legislative Assembly of Nunavut
P. O. Box 2410
Iqaluit, NU X0A 0H0

Dear Minister Ehaloak;

RE: Utility Rate Review Council's General Rate Application Report # 2018-01.

Please find attached the Utility Rate Review Council's General Rate Application Report # 2018-01, which is due to you on March 26, 2018.

Yours truly,

Anthony Rose
Chair
Utility Rates Review Council of Nunavut (URRC)

CC: Hon. Paul Quassa, Minister Responsible for the URRC
Kathy Okpik, Deputy Minister Executive
& Intergovernmental Affairs (EIA)
Bruno Pereira, President QEC
Laurie-Anne White, ED URRC

P.O. Box 1000, Stn 200, Iqaluit, NU, X0A 0H0
Tel: 867-975-6054 URRC@gov.nu.ca

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Report to the Responsible Minister for the Qulliq Energy Corporation On:

Qulliq Energy Corporation's 2018/19 General Rate Application

Report 2018-01

March 26, 2018

THE UTILITY RATES REVIEW COUNCIL

MEMBERS	Anthony Rose	Chair
	Graham Lock	Vice Chair
	Robbin Sinclaire	Member
	Nadia Ciccone	Member

SUPPORT

	Laurie-Anne White	Executive Director
	Raj Retnanandan	Consultant
	Monica Ell-Kanayuk	Interpreter

QEC WITNESSES

The following attended one or more community consultations as representatives of Qulliq Energy Corporation:

Bruno Pereira	President and CEO QEC
Darryl Taylor	Manager Planning and Analysis
Sheila Papa	Acting Director Corporate Affairs
Renee Boucher	Acting Manager Corporate Communications

LIST OF ABBREVIATIONS

AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
AUC	Alberta Utilities Commission
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
CEO	Chief Executive Officer
CPC	Capital Planning Committee
EPCM	Engineering, Procurement, Construction Management
FTE	Full Time Equivalents
FSR	Fuel Stabilization Rider
HSE	Health, Safety and Environment
GN	Government of Nunavut
GRA	General Rate Application
HR	Human Resources
kWh	Kilowatt Hour
MWh	Megawatt Hour
NUL	Northland Utilities (NWT) Limited
O&M	Operation & Maintenance
NTPC	Northwest Territories Power Corporation
NESP	Nunavut Electricity Subsidy Program
MPP	Major Project Permit
PPD	Petroleum Products Division
PSA	Public Sector Accounting Standards

QEC	Qulliq Energy Corporation
ROE	Return on Equity
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UPC	Usage Per Customer
URRC	Utilities Rates Review Council
YEC	Yukon Energy Corporation
WHMIS	Workplace Hazardous Materials Information System

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EXECUTIVE SUMMARY

1. Qulliq Energy Corporation (QEC) filed a General Rate Application (GRA) with respect to the 2018/19 test year which requested, among others:

   - A reduction in the existing base rate revenues by $864,000 to reflect the 2018/19 test year forecast revenue requirement of $134.047 million.
   - Approval of a revenue phase in mechanism starting with the elimination of the Fuel Stabilization Rider refund of 5.41¢/kWh on April 1, 2018 effectively returning rates to base rates approved in the 2014 GRA. If eliminating the Fuel.
   - Stabilization Rider (FSR) results in 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.
   - Realignment of existing community based rates to reflect Nunavut wide cost of service rates, through a 6 year rate realignment process, commencing in 2018/19. QEC proposed a 5% maximum realignment increase per year.

2. The Utilities Rate Review Council (URRC) supports the proposed move towards rates for all communities based on Nunavut wide cost of service. However, the URRC considered that the maximum rate realignment increases resulting therefrom should be limited to 3% in each of 2018/19 and 2019/20 in order to preserve rate stability for all customers. The URRC did consider that the Nunavut Electricity Subsidy Program (NESP) subsidizes rates for eligible consumption in all Nunavut communities is calculated at 50% percent of the Iqaluit base rate. Thus, a significant increase in rates for Iqaluit means corresponding increases in customer bills in other communities.

3. Based on the revenue requirement recommended by the URRC, the following Table provides a comparison of the changes in total energy revenue proposed by QEC and those recommended for approval by the URRC:

	Changes in Energy Revenues					
		Pre April 1, 2018	**April 1, 2018 to March 31, 2019 Per QEC**	**April 1, 2018 to March 31, 2019 Per URRC**	**April 1, 2019 Forward Per QEC**	**April 1, 2019 Forward Per URRC**
		A	**B**	**C**	**D**	**E**
		$000	$000	$000	$000	$000
1	Base Energy Revenue	125841	125841	125841	121317	121317
2	FSR Rider Revenue (1)	-9676				
3	QEC proposed surplus at existing base rates (2)		-864	-864		
4	QEC Proposed Phase in adjustment (3)		-3660	-3660		
5	2018/19 Revenue deficiency as per URRC				3660	3167
6	Energy Revenue (4)	116165	121317	121317	124977	124484
7	Percent change		4.4%	4.4%	3.0%	2.6%
	Notes:					
	1. Based on 178,851 MWh sales times $0.0541 FSR credit Rider					
	2. Difference between existing base revenues and QEC proposed revenue requirement;see Table 5.3 Page 5-4					
	3. Revenue Phase in reduction proposed by QEC; see page 8-12; L19					
	4. Does not include customer fixed charge and demand charge revenues					

4. Furthermore, the table above demonstrates that the energy revenue increase in 2018/19 which compared with prior year energy revenues is 4.4%. For 2019/20, the energy revenue increase proposed by QEC is 3.0% and the energy revenue increase recommended by the URRC is 2.6%.

5. Noting that Iqaluit is among the lowest rate communities and therefore subject to the maximum rate realignment increases. These above-mentioned revenue changes translate to rate changes as follows for Iqaluit:

	Domestic & Commercial Rate Changes for Iqaluit-QEC Proposed and Per URRC										
		Units18/19	**Units19/20**	**Domestic**				**Commercial**			
				2018/19		2019/20		2018/19		2019/20	
				Per QEC	Per URRC	Per QEC	Per URRC	Per QEC	Per URRC	Per QEC	Per URRC
1	Base Energy Rate	c/kW.h	c/kW.h	60.29	60.29	60.29	59.56	50.68	50.68	50.68	49.67
2	Fuel Rider	c/kW.h		-5.41	-5.41			-5.41	-5.41		
3	Rate Level Prior Year	c/kW.h	c/kW.h	54.88	54.88	60.29	59.56	45.27	45.27	50.68	49.67
4	Reduction to Base Rates per QEC	0.6868%			-0.41				-0.41		
5	Revenue Phase in Adjustment	c/kW.h			-2.046				-2.046		
6	2019/20 Revenue Increase		2.610%				1.55				1.30
7	Base Rate Before Realignment [L1+4+5+6]	c/kW.h	c/kW.h		57.83		61.12		48.22		50.96
8	Realignment Increase	3%	3%		1.73		1.83		1.45		1.53
9	2018/19 Base Rate	c/kW.h	c/kW.h	60.29	59.56	65.46	62.95	50.68	49.67	55.03	52.49
10	Percent change over prior year [L7/L3-1]	%	%	9.9%	8.5%	8.6%	5.7%	12.0%	9.7%	8.6%	5.7%

6. Addionally, the table above indicates that the maximum increase in energy rates proposed by QEC for Domestic customers in Iqaluit to transition out of the FSR credit rider and to realign community based rates is 18.5% (9.9%+8.6%) over two years. This is in comparison with 14.2% (8.5%%+5.7%) recommended for approval by the URRC. Also, the same table indicates that the maximum increase in energy rates proposed by QEC for Commercial customers in Iqaluit to transition out of the Fuel Stabilization Rider (FSR) credit rider and to realign community based rates is 20.6% (12.0%+8.6%) over two years. This is in comparision with 15.4% (9.7%+5.7%) recommended for approval by the URRC. Lastly, the URRC did not recommend approval of any further rate realignment changes for any community until the next GRA.

7. The URRC notes the significant variances between the costs for major projects as approved at the time of Major Project Permit Applications and the actual (or forecast) costs. Thus, the URRC recommended that QEC be directed to file an amended application with the Minister if the projected costs for a major project prior to construction exceeds the amount approved by the Minister, by more than 25% or $5 million, whichever is greater.

8. QEC proposed the addition of a power plant in Grise Fiord to rate base at a cost of $20 million in 2018/19. This plant is intended to serve a community of 103 customers. The existing installed capacity in Grise Fiord is 570 kW and the replacement plant would have a capacity of 1000 KW. This translates to an almost doubling of the installed capacity per customer.

9. The URRC found there is little evidence of practicing due diligence on the part of QEC management in relation to planning the project and evaluating cost effective design and construction alternatives prior to awarding the fixed price contract for construction of this plant to Engineering, Procurement, Construction Management (EPCM). The URRC noted the plant replacement cost per kW at Grise Fiord is $20,000/kW as compared to $8956 per kW in Qikiqtarjuaq and $8587/kW in Taloyoak. The URRC considered that the customers of QEC should not have to bear the burden of any unjustified costs incurred by QEC. Accordingly, for the purposes of this report, the URRC recommended that the proposed cost

of the Grise Fiord plant addition to be included in rate base should be adjusted from $20.0 million to $14.9 million.

10. Consequently, in response to this observation of unjustified construction costs. The URRC recommended that the Finance and Audit Committee which reports to QEC’s Board of Directors provide a report annually to the Minister Responsible, detailing its independent assessment of the effective implementation of the requirements set out in QEC’s capital planning manual. This is recommended to be carried out until the next GRA.

11. With respect to alternative energy projects, the URRC stated that it looks forward to the Alternative Energy Committee’s involvement in integration of renewables into Nunavut’s electrical generation systems.

12. The URRC expressed concern that the current asset accounting practices may not ensure accountability on the part of those responsible for asset retirements/dispositions and plant write offs. Therefore, to maximize the potential value of investments in retired or disposed plant, the URRC recommended that QEC be directed to implement or augment mechanisms to ensure due accountability. In addition to controls and approvals for all activities including retirements, dispositions and write offs. This would minimize the potential for leakage of value arising from such transactions.

13. The URRC expressed concern respecting the 2.5 times increase in the level of supplies inventory since the last GRA in 2014/15. Noting the Auditor General of Canada’s opinion on this matter in their 2016/17 Annual Report, the URRC concluded that prudent control of spares and supplies must be demonstrated at the time of the next GRA. Therefore, the URRC recommended that QEC be directed to implement or augment mechanisms to facilitate verifiability of physical inventory quantities. And to take immediate steps to implement procedures and practices for efficient management of inventory levels and the exercise of appropriate controls over all inventory transactions.

14. The URRC recommended that assets that are no longer in use and assets that are the subject of insurance claims should be removed from the regulatory accounting records before applying the applicable depreciation rates. Noting a $38 million liability for contaminated sites identified in the 2016/17 Annual Report, the URRC recommended that the identities of the life portion and the salvage portion of accumulated depreciation account be tracked separately for regulatory purposes. The URRC further recommended that QEC address the appropriate treatment of a provision for negative salvage including future retirement and site restoration as part of the next depreciation study.

15. The URRC recommended awarding QEC a rate of return on equity of 8.30% considering the business risks of QEC to be no higher than those of a generic Canadian utility determined by the Alberta Utilities Commission (AUC) in Decision 20622-D01-2016 dated October 7, 2016. This Decision examined the generic risks of many different categories of utilities. The Auditor General’s conclusion was that QEC is not a rate regulated utility. This is based on the finding that the Corporation is unable to recover its costs without significant direct or indirect financial support from the GN. It suggests QEC’s exposure to business risks are being mitigated through GN financial support. And this risk would be no greater than those of a generic utility in the relevant category as considered by the AUC.

1.0 BACKGROUND

1.1 REGULATORY HISTORY

16. Qulliq Energy Corporation (QEC or Corporation), filed a General Rate Application (GRA or Application) for the April 1, 2018, to March 31, 2019, Test Year (2018/19 Test Year) with the responsible Minister for QEC, on October 27, 2017. The responsible Minister referred the matter to the Utility Rates Review Council (URRC) for review and recommendations, pursuant to Section 12 of the *Utility Rate Review Council Act* (the Act). This is the fourth GRA filed by QEC since division from the Northwest Territories Power Corporation (NTPC).

17. The first GRA following division of QEC from NTPC on April 1, 2001 was for the Test Year April 1, 2004, to March 1, 2005 (2004/05 Test Year). The URRC's Report to the responsible Minister respecting the matters raised in QEC's 2004/05 GRA was issued on January 27, 2005, followed by a final Report on February 18, 2005.

18. In February 2005, the responsible Minister provided Instructions authorizing an increase of 15% to electricity rates across all communities and rate classes in Nunavut. These rates took effect April 1, 2005. Further to this increase, the URRC requested the Corporation to return with certain specific information before, or as part of, any request for a further increase. This information was submitted to the URRC on May 9, 2006. The result of the May 9, 2006, application was a further 5.44% general rate increase for all electricity consumed in Nunavut, effective October 1, 2006.

19. QEC filed its second GRA filing in October 4, 2010. The URRC issued Report 2010-01 with respect to the 2010/11 test year giving effect to increases in energy rates of 6.0% (November 1, 2010), 4.50% (April 1, 2011) and 4.43% (April 1, 2012).

20. The third GRA with respect to the 2014/15 GRA was filed on November 1, 2013, then withdrawn and resubmitted on December 20, 2013. Report 2014-04 and Final Reports 2014-05 gave effect to a 7.1% increase in energy rates effective May 1, 2014.

21. Following the 2014/15 GRA, QEC requested and received approvals for adjustment of fuel stabilization riders (FSR) from time to time. The most recent FSR application was a request from QEC for an FSR credit of $0.0541 per Kilowatt Hour (kWh) for the period October 1, 2017, to March 31, 2018. This application was approved in URRC Report 2017-03, dated November 6, 2017.

1.2 CORPORATE ORGANIZATION & DUTIES

22. QEC is a Crown Corporation, 100% owned by the Government of Nunavut (GN). It is incorporated and operates under the Qulliq Energy Act.

23. QEC's 2016/17 Annual report indicates that the Corporation delivers electricity to approximately 15,000 customers across Nunavut. QEC generates and distributes power to Nunavummiut through the operation of 25 stand-alone diesel power plants in 25 communities, with a total installed capacity of approximately 76,000 kW. The Corporation also provides mechanical, electrical and line maintenance from three regional centers: Iqaluit, Rankin Inlet and Cambridge Bay. The Corporation's business activities are maintained at the Head Office located in Baker Lake and corporate offices in Iqaluit.

24. QEC is the only generator, transmitter and distributor of electrical energy for retail supply in Nunavut. The Corporation serves a population of approximately 37,000 people 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.

25. QEC's Board of Directors is appointed by the Minister responsible for QEC. Under the QEC Act, the Board of Directors is composed of six to ten Directors. The President and Chief Executive Officer (CEO) of the Corporation reports to the Board of Directors.

26. There are three Board Committees, namely the Human Resources Committee, the Audit and Finance Committee and the Alternative Energy Committee.

27. QEC's 2016/17 Annual Report notes that the Human Resources Committee provides recommendations relating to the Corporation's organizational workforce. The committee reviews human resources and compensation matters pertaining to the senior management team. In addition, the committee evaluates: programs and initiatives related to Inuit employment; training and development; employee and labour relation environments; implementation of collective agreements; and initiatives aimed to improve the capability and capacity of employee performance results.

28. The 2016/17 Annual Report notes that the Finance and Audit Committee assists the Board in meeting its oversight and financial responsibilities and accountabilities to the Corporation and its stakeholders: the Government of Nunavut and the ratepayers of Nunavut. The committee facilitates communication between the Board and the external auditor and is the presiding body related to the activities of the internal auditor.

29. The 2016/17 Annual Report notes that the Alternative Energy Committee provides recommendations to the Board regarding the viability of alternative or renewable energy technologies in the North. The committee also provides input on financing options and financing sources for development, demonstration projects, research initiatives, collaboration opportunities, and supportive and overlapping mandates of other organizations.

30. As of March 31, 2017, QEC had 206.8 full time positions of which 186.2 were filled.

31. QEC's 2016/17 Annual Report indicates, the department of Engineering is responsible for planning, design, project management, technical support services and life cycle analysis for new and existing power plant infrastructure for the Corporation. Engineering also oversees the development and implementation of professional standards, project management procedures, Computer Aided Design, and maintenance of the engineering document

management system. The strategic partnership between the Engineering and Operations departments ensures support for daily operational issues, long term planning, and execution of QEC's Corporate Plan.

32. QEC's 2016/17 Annual Report indicates that the department of Operations is tasked with the mandate of generating and distributing safe, reliable electricity to all Nunavut communities. Each community has its own power plant operated by employees who live in the community. Local employees are supported by electrical, mechanical and power line technicians based in the regional centers of Cambridge Bay, Iqaluit and Rankin Inlet. In addition to its core responsibility of electricity generation and distribution to the territory, Operations works closely with the department of Engineering to facilitate and execute QEC's capital plan.

1.3 JURISDICTION & MANDATE OF URRC

33. The Act requires the Corporation, as the supplier of electricity in Nunavut, to obtain the approval of the responsible Minister for any proposed rate changes. Before approving the Corporation's rates, the responsible Minister is required to seek the advice of the URRC.

34. In the case of Major applications, such as the current GRA, the URRC is required to report to the responsible Minister within 150 days following receipt of a Request for Advice. The report is to indicate whether:

a) the imposition of the proposed rate or tariff should be allowed;
b) the imposition of the proposed rate or tariff should not be allowed; or
c) another rate or tariff specified by URRC should be imposed.

35. In making its report, the URRC is required to have regard to whether the proposed rate or tariff is fair and reasonable considering, among other things, the cost of providing the service, including related financing costs.

36. In carrying out its purposes under the Act, the URRC is permitted to:

a) hold public and private meetings;

b) retain the services of experts and advisors;

c) solicit advice from the public;

d) conduct meetings and mediations with utilities and concerned parties and assist utilities and their customers in developing a consensus on contentious issues;

e) require utilities and their employees to provide all information needed to carry out its purposes and may require that information to be provided under oath or by way of solemn declaration; and

f) generally engage in activities that assist it in providing informed advice to the responsible Minister.

37. Pursuant to the Request for Advice from the responsible Minister, dated October 27, 2017 the URRC conducted the proceedings in accordance with the requirements and parameters specified in the Act. This report sets out the URRC's recommendations to the responsible Minister.

2.0 APPLICATION

38. The first part of the GRA application is for approval of the 2018/19 revenue requirement and determination of the forecast revenues for the same fiscal year (Phase I). As shown in Table 1, line 7, the revenues at existing base rates are higher than the 2018/19 forecast revenue requirement by $864,000. QEC's proposal is to reduce the $864,000 surplus of revenues over revenue requirement, to customers in 2018/19.

39. The Application also requests approval of a revenue phase-in mechanism whereby the customer impact from termination of the 5.41¢/kWh FSR rider would be phased in over a period of 2 years (2018/19 and 2019/20). Further, as part of the Phase II application, QEC requested approval of rates, effective April 1, 2018 and April 1, 2019, that would gradually move community based rates towards uniform rates which would recover the Nunavut wide cost of service; QEC requested that the phase-in period be completed in 6 years, commencing in 2018/19.

40. The net revenue impact in 2018/19 of the revenue phase in mechanism referred to above and the realignment of rates towards recovery of costs based on a Nunavut wide cost is a reduction in base rate revenues of $3.66 million. As a result, QEC forecast a revenue deficiency of $3.66 million for 2018/19 as shown in Table 1. For rates effective 2019/20, QEC requested that the base rates be increased by $3.66 million while at the same time giving effect to further realignment of rates towards uniform Nunavut wide rates.

41. The following Table 1 shows the proposed revenue requirement and changes in revenues requested by QEC for 2018/19 and for 2019/20:

	Table 1-Revenue Requirement & Revenues-QEC Proposed		
		2018/19	2019/20
		$000	$000
1	Revenue Requirement	134047	134047
2	Revenue Offsets	-2548	-2548
3	Rate Level Revenue Requirement	131499	131499
4	Energy revenue at existing base rates	125841	
5	Customer & demand revenue at proposed rates	6522	
6	Revenue at existing rates	132363	
7	Rate reduction to align existing rate revenue with revenue requirement	-864	
8	Rate reduction for revenue phase in and rate realignment	-3660	
9	Sales revenue	127839	127839
10	Rate increase for revenue phase in and rate realignment		3660
11	Sales revenue at proposed rates	127839	131499
12	Revenue shortfall 2018/19	-3660	0

42. The forecast revenue deficiency of $3.66 million in 2018/19 would reduce QEC's return on equity for that year. However, QEC requests that the rates be increased to recover the forecast rate level revenue requirement of $131.499 million in 2019/20.

3.0 PROCESS FOR HEARING OF THE APPLICATION

43. Upon receipt of the Application, the URRC established a process for examination and hearing of the Application. Notice of the Application and the location and timing of community consultation meetings was advertised in various media.

44. As part of the process for examination of the Application, the URRC issued two rounds of information requests to QEC. Responses to information request on or about December 15, 2017. Portions of QEC's responses to URRC QEC 16 were considered confidential by QEC as they relate to commercial terms agreed to with providers of Engineering, Procurement, Construction Management (EPCM) services in the context of new power plant construction projects. QEC's responses to the second round of information requests was received on February 16, 2018; certain portions of URRC QEC 37, 38 and 39 were considered

confidential for the same reasons as stated before. As part of the process for receiving input from interested parties, the URRC held a number of community consultation meetings with concerned citizens in December 2017 and January 2018 at the following locations:

Date	Time	Location	Community
Kivalliq and Kitikmeot			
December 4, 2017	7-9 pm	Katimavik Conference Room	Rankin Inlet
December 5, 2017	7-9 pm	Community Hall / Arena	Baker Lak
December 6, 2017	7-9 pm	Community Hall	Kugluktuk
December 7, 2017	7-9 pm	Community Hall	Cambridge Bay
Qikiqtaaluk			
January 8, 2018	7-9 pm	Community Hall	Pond Inlet
January 9, 2018	7-9 pm	Community Hall	Igloolik
January 10, 2018	7-9 pm	Community Hall	Cape Dorset
January 11, 2018	7-9 pm	Parish Hall	Iqaluit
January 12, 2018	7-9 pm	Community Hall	Qikiqtarjuaq
January 13, 2018	1-3PM	Francophone Center	Iqaluit

45. In addition to community meetings, radio announcements were made at the regional and community levels. Announcements were also posted on local bulletin boards.

46. At each of the meetings, the URRC Chair introduced the URRC panel members, explained its role in the process, the legislative mandate of the URRC and the desire to gain as much input as possible from affected parties.

47. At the meetings, QEC presented a panel of witnesses headed by the President of the Corporation to explain the requirement for the requested rate increase, the recommendation to move to Nunavut wide uniform rates, and to respond to questions. Meeting participants were provided an opportunity to make statements and ask questions of QEC's panel on the Application.

48. The notes pertaining to the meetings are attached hereto as Appendix 1.

49. Written submissions with respect to the Application were received on February 2, 2016. QEC’s response to comments from parties was received on February 23, 2018.

50. The URRC would like to thank all of the individuals and organizations who attended the meetings and/ or provided submissions respecting the proposed power rate increases. These individuals and organizations will be collectively referred to as parties to the proceeding. The URRC will not provide a summary of each and every one of the submissions, but will include the comments from parties, as applicable, with respect to specific issues.

4.0 EXAMINATION OF THE APPLICATION

51. Section 13 (2) of the Act states the URRC must have regard to whether the proposed rate or tariff is fair and reasonable considering the cost of providing service, including financing costs and other factors set out in the Guidelines. Sections 1(1) and 1(2) of the Guidelines require the URRC to determine the costs of providing service (revenue requirement) having regard to the following:

> **1(1) Total Cost Recovery**
> Rates should be set so that looking ahead each year the total revenue the utility earns from the rates will match the total cost of providing services as determined under these guidelines.
>
> **1(2) Traditional Regulatory Approach**
> The total cost of providing services should be determined using principles commonly applied in Canada to regulated utilities. Some key features of that approach are:
>
> a) Determine the value of all the property the utility uses or needs to provide the service.
> b) In determining the value of the property used or needed,
>   i) consider the reasonableness of the utility's forecast of customer growth, system use, and sales, and its plans for adding and upgrading plant and equipment in view of that forecast and the need to provide safe reliable service;
>   ii) use the cost of property when first put into service taking into account what the utility acting wisely should have paid for it and any depreciation, amortization or depletion; and
>   iii) consider necessary working capital.
> c) Once the total value of the property has been determined, decide on a suitable mix of equity and debt for financing the property, and allow as costs
>   i) a fair return on the equity part, and
>   ii) reasonable interest and related costs for the debt part.
> d) In addition to these costs, include all other costs that appear reasonably necessary for the utility to provide services, for example:
>   i) all reasonable operations and maintenance expenses,
>   ii) fuel costs,
>   iii) taxes, and
>   iv) any other costs the utility must incur to provide safe, reliable service.

In any case where the Review Council is requested to provide advice to Government, it may base its analysis on these and other generally accepted regulatory principles.

52. The URRC’s examination and assessment of the Application are based on the Corporation's Annual Reports, technical and financial information made available by the Corporation as part of the Application, responses to information requests and QEC's written submission dated February 23, 2018.

5.0 REVENUE REQUIREMENT AND REVENUES (PHASE I MATTERS)

5.1 COMPONENTS OF REVENUE REQUIREMENT AND REVENUES

53. The Components of revenue requirement are fuel and lubricants, non-fuel operating and maintenance expenses, amortization (or depreciation) expense and return on rate base. The rate base is comprised of plant in service and working capital.

54. The components of revenues are sales revenues and non-electric revenues. The forecast revenues are compared with forecast costs to arrive at the revenue surplus or shortfall.

5.2 MAJOR ADDITIONS TO PLANT

55. The following Table 2 sets out the costs of major plant replacement additions added to rate base and proposed to be added in 2018/19:

Table 2-Major Plant Additions

	Community	Customers 18/19	Installed Capacity (KW)		Inst. Capacity/Customer		Replacement		
			Before Replacement	After Replacement	Before Replacement	After Replacement	Year of Rate Base	Cost $m	Cost in $/kW
1	Taloyoak	352	1570	1840	4.5	5.2	2016/17	15.8	8587
2	Qikiqtarjuaq	285	1320	1820	4.6	6.4	2016/17	16.3	8956
3	Pangnirtung	602	2630	2880	4.4	4.8	2017/18	19.0	6597
4	Grise Fiord	103	570	1000	5.5	9.7	2018/19	20.0	20000

56. The Pangnirtung plant replacement is the result of a fire that destroyed the power plant in April 2015. QEC's 2016/17 Annual Report states that completing the community's new power plant was one of the department's priorities for 2016-2017; to meet this goal, Engineering adapted a design-build concept to expedite the completion of Pangnirtung's new plant. Design-build is a project delivery method led by a single contractor covering all activities resulting in time and cost savings. QEC states following the design build approach led by a single contractor, the new plant was completed in less than two years; the typical planning, procurement, and construction cycle for a new power plant takes approximately three years or more.

57. The Taloyoak Plant Replacement Major Project Permit (MPP) application reflects an estimated cost of $10.8 million with a plus or minus 25% accuracy level for a capacity addition of 1700 to 1850 kW in 2013/14; the corresponding actual cost of addition in 2016/17 is $15.8 million.

58. The Qikiqtarjuaq Plant Replacement MPP application reflects an estimated cost of $8.2 million with a plus or minus 25% accuracy level for a capacity addition of 1220 to 1350 kW in 2013/14; the corresponding actual cost of addition in 2016/17 is $16.3 million.

59. The Grise Fiord Plant Replacement MPP application reflects an estimated cost of $7.9 million for a capacity addition of 600 kW in 2015/16. The corresponding forecast cost of addition in 2018/19 is $20.0 million.

60. QEC states that the main factor for the cost projection variances from the MPP estimates is the timing of the estimates, rather than cost overruns, and inherent uncertainty associated with tender results experienced in the north. QEC states, for large capital projects, the MPP application must be filed very early in the project planning process. QEC states that the MPP timeline requirements are such that QEC cannot have detailed project design and tender results available to prepare budgets; unless QEC has had very recent experience with a project of similar scope, the project cost estimates used in the MPP application will be very

preliminary. QEC states that it updates project budget estimates when bidder prices are reviewed, which typically occurs long after the project permit is issued.

61. QEC states the capital planning manual sets out the process for adjusting project budgets; the Capital Planning Committee (CPC) is responsible for the oversight of capital planning and management at QEC; in accordance with the new procedure, CPC and QEC's senior management receive regular updates on project status and progress; QEC staff performing the implementation of a capital project are now responsible for following the process as outlined in the capital planning manual. [URRC QEC 33c)]

62. QEC's Capital Planning Manual is provided in URRC-QEC-1-33 Attachment 1. QEC states, this manual was developed in response to the URRC's recommendation #1 from Report 2014-4. QEC states, the manual includes QEC's capital planning policy, and provides guidance for implementing the requirements of the policy, including variance reporting and project close-out requirements.

63. QEC states that the Taloyoak and Qikiqtarjuaq plant replacements were completed in 2016/17 and as such were not subject to all the requirements of the policy. QEC states that the Grise Fiord project is forecast to be in service in 2018/19 and the procedures outlined in the manual will apply to the Grise Fiord Project. [URRC QEC 33d)]

URRC Findings:

64. In recommending approval of an MPP to the Minister, the URRC assumes certain responsibilities in terms of assessing the need for the project, whether the proposed project option and corresponding costs are optimal considering rate impacts, reliability, and QEC's strategic objectives. Typically, the level of accuracy of costs in a project permit application is understood to be plus or minus 25%. If following approval of an MPP, the project concept or costs were to change substantially, the original recommendations on the MPP become redundant. In order to avoid this eventuality, for future MPP applications, the URRC recommends that the Minister direct QEC to file an updated project permit application if, the

projected costs determined prior to project commencement exceed the project permit amount approved by the Minister, by more than 25% or $5 million, whichever is lower, and provide justification for the changes.

65. With respect to the Pangnirtung plant replacement, the URRC notes certain efficiencies were achieved through the design build approach led by a single contractor; the cost per kW of plant addition of $6597/kW is the lowest among the major projects shown in Table 2. For the purposes of this report, the URRC accepts the proposed addition of the Pangnirtung plant at a cost of $19.0 million to rate base and expects the Pangnirtung model for efficiencies could be replicated for other projects where possible.

66. With respect to the Taloyoak and Qikiqtarjuaq plant replacements the URRC notes that the installed capacities of each of these plants reasonably match the respective required firm capacities as per Table 2 of URRC QEC 2-38c)]:

Table 2: Taloyoak and Qikiqtarjuaq Required Firm Capacity Forecasts

Community	Installed Capacity (KW)	Largest Unit (KW)	Firm Installed Capacity (KW)	2016/17 Fiscal Year Actual		2041/42 Fiscal Year Estimate	
				Community Peak, kW	Required Firm Capacity, kW	Community Peak, kW	Required Firm Capacity, kW
Taloyoak G1 - 370 kW G2 - 550 kW G3 - 550 kW G4 - 370 kW	1,840	550	1,290	730	803	1,320	1,452
Qikiqtarjuaq G1 - 350 kW G2 - 550 kW G3 - 550 kW G4 - 370 kW	1,820	550	1,270	505	556	930	1,023

67. It is not clear whether the design build approach led by a single contractor approach was followed in the case of the Taloyoak and Qikiqtarjuaq plants. However, the cost per kW of plant addition of $8587/kW for the Taloyoak plant and $8956/kW for the Qikiqtarjuaq plant is higher than the corresponding cost for the Pangnirtung plant replacement. The URRC considers the smaller size of these communities compared with Pangnirtung may mean a higher proportion of fixed costs for the Taloyoak and Qikiqtarjuaq plant replacements. This may explain the higher costs per kW. In the absence of any evidence to the contrary, for the

purposes of this report, the URRC considers the Taloyoak and Qikiqtarjuaq plant replacement costs to be reasonable and accepts the proposed addition of these plants to rate base as proposed.

68. The Grise Fiord plant proposed to be added to rate base at a cost of $20 million in 2018/19 is intended to serve a community of 100 customers. The existing installed capacity is 570 kW and the replacement plant would have a capacity of 1000 kW. The URRC does not understand why QEC considered it necessary to design a 1000 kW plant to replace an existing plant with a capacity of 570 kW particularly in a community that is not forecast to grow.

69. The Grise Fiord plant, unlike the Pangnirtung model is being constructed as a prefabricated plant under an EPCM contract. The main EPCM contractor's fixed price includes, design and transportation (sealift) of a prefabricated plant to the site, managing the logistics of installing the plant at the site as well as the prefabrication cost of plant and equipment payable to a subcontractor.

70. In the URRC's view, there is little evidence of the exercise of due diligence on the part of QEC management in relation to planning the project and evaluating cost effective design and construction alternatives prior to awarding the fixed price EPCM contract. One example of lack of due diligence is the increase in installed capacity from 570 kW to 1000 kW for a community with 103 customers and declining. This translates to an almost doubling of installed capacity for a community where the population is not expected to grow. Further, the contract documents do not include a detailed breakout of the lump sum fixed price contract showing quantities and unit prices for various plant components, labour, transportation etc.

71. About 37% of the contracted fixed price is payable to the EPCM contractor for administration, profit and managing the logistics of transporting the prefabricated plant to the site and installing the power plant at the site. The costs for transporting the plant and installing at the site include costs which appear to be out of proportion to the size of the

community. About 44% of the contracted fixed price is payable to the sub contracted supplier of prefabricated equipment.

72. The URRC notes the plant replacement cost per kW at Grise Fiord is $20,000 /kW as compared to $8956 per kW in Qikiqtarjuaq and $8587/kW in Taloyoak. The URRC considers that the customers of QEC should not have to bear the burden of any unjustified costs incurred by QEC.

73. For the purposes of this report, the URRC considers it appropriate to adjust the cost of the Grise Fiord plant to be included in rate base for 2018/19 as per Table 2A:

Table 2A-Grise Fiord Plant Capital Cost Adjustment

		Per QEC URRC QEC 1-16	Per URRC
		000	000
1	Construction cost per Table 4 URRC QEC 1-16 Public	16516	13516
2	Contingency	1473	0
3	Overhead @4.5%		608
4	AFUDC @ 5.3% on average investment over 2 Years		716
5	Overhead & AFUDC	1980	
6	Total	19969	14841
7	URRC Reduction to Cost of Addition to Rate Base		5128
8	Mid Year reduction to cost of addition to Rate Base		2564
9	2018/19 Revenue Requirement Impact:		
10	Return @5.3%		136
11	Depreciation @ 3.65% for Diesel Plant		94
12	Total 2018/19 Revenue Requirement Impact		229

74. Line 1 of Table 2A shows a reduction of $3 million in the fixed price contract which is a reduction to the costs for transportation and installation of the prefabricated plant at the site. Line 2 shows the disallowance of the contingency amount since the contract is a fixed price contract; line 3 shows 4.5% overhead which is 50% of the overhead rate of 9% QEC charges for overhead. The URRC considers that since the entire project was designed and constructed

by the EPCM contractor, a lower overhead rate would be appropriate. Line 12 shows that the disallowances would result in a reduction in revenue requirement of $229,000 in 2018/19.

75. Since the above are disallowances for unjustified costs, URRC recommends that QEC be directed to reduce the actual costs of the Grise Fiord plant to be included in rate base for future rate applications, in a manner consistent with the forecast reduction of $5.1 million as shown in Table 2A. This treatment would be consistent with the regulatory treatment of the disallowed costs from the Baker Lake project as shown in the detailed calculation of the 2018/19 rate base in URRC QEC 44, Attachment 1.

5.3 PLANT RETIREMENTS

76. The following Table 3 shows the plant retirements by year since the 2014/15 GRA to the 2018/19 test year:

Table 3-Plant Retirements

	$m
2014/15 GRA	0.0
2014/15 Act	0.3
2015/16 Act	6.6
2016/17 Prelim. Act	1.0
2017/18 Fore	0.0
2018/19 Fore	0.0
Source: Schedule 6.1	

77. QEC identified the major plant retirements as the reasons for retirement as follows in Table 3 of URRC QEC 2-44:

Table 3: List of disposals/retirements with more than $200,000 cost [excludes Pangnirtung]

Disposed/Retired Asset	Original Cost		Accumulated Amortization		Loss/(Gain) on Disposal	Reason for Disposal
	2015/16	2016/17	2015/16	2016/17		
Prime Mover, CAT D398	422,530		422,530		-	Was put in service in 1986 and reached the end of its srvice life based on operation hours. The new unit was installed in 2014/15.
Prime Mover, CAT 399	200,000		200,000		-	Was put in service in 1984 and reached the end of its srvice life based on operation hours. The new unit was installed in 2014/15.
Wind Turbine, 80 kw LW 18/80	290,590		290,590		-	Units were non operational for several years. In order to avoid possible hazard to community was removed.
Wind Turbine, 80 kw LW 18/80	200,500		200,500		-	
Wind Turbine, Generator	341,679		341,679		-	Unit went overspeed on June 12, 2015 and blew apart.
Prime Mover, D 3512	425,554		345,322		80,232	G1 D3512 had problems with reliability and operation. It was recommended that this unit should be replaced with a more reliable unit of similar capacity. The new unit was installed in 2015/16.
Prime Mover, DD2000	340,767		209,399		131,368	G1 had reliability and operational concerns and was recommended to replace unit. The unit had no resale value. The new unit was installed in 2016/17.
Prime Mover, SF360TA	358,310		77,768		280,542	Failed due to a crank through the block. The new unit was installed in 2015/16.
Prime Mover, DD S2000		410,056		254,575	155,481	Units had a history of break downs and required replacement with for reliability units. Replaced as part of capacity increase project.
Generator, Stamford		238,926		129,127	109,799	
Wind Monitoring Tower [Research & Development]		271,084		26,303	244,781	This was related to Research & Development mistakenly capitalized. There was also no current or future usefulness.
Total [projects with more than $200,000 cost; also excludes Pangnirtung plant]	**2,670,020**	**920,065**	**2,177,877**	**410,005**	**1,002,203**	

78. QEC also provided a comprehensive listing of asset retirements and the related accumulated depreciation as follows in Table 1 of URRC QEC 1-14:

Table 1: List of Gross Plant Disposals for 2014/15 through 2016/17 Actual Years

	PP&E			Accumulated depreciation		
	2014/15	2015/16	2016/17	2014/15	2015/16	2016/17
2006 F-150 S/C 4x4	44,604			29,994		
2002 F-150 S/C 4x4	32,551			32,551		
2001 Ford Explorer	22,841			14,522		
2003 F-150 S/C 4x4	44,438			41,819		
2005 F-150 C/C 4x4	45,931			35,002		
2005 F-150 C/C 4x4	22,174			16,898		
1991 Digger/Derrick	55,000			55,000		
2006 F-150 S/C 4x4	45,006			30,263		
Access Elec Equip, KATO Generator		63,421			47,514	
Prime Mover, CAT D398		422,530			422,530	
Acc Elec Equip, CAT 3512		41,380			31,002	
Truck, 2005 Ford F150 4x4		44,779			37,274	
Truck, 2002 Ford Explorer		36,000			36,000	
Prime Mover, CAT 399		200,000			200,000	
Generator, ABB		100,000			100,000	
Wind Turbine, 80 kw LW 18/80		290,590			290,590	
Wind Turbine, 80 kw LW 18/80		290,590			290,590	
Wind Turbine, 80 kw LW 18/81		40,115			40,115	
Wind Turbine, 80 kw LW 18/80		40,115			40,115	
Wind Turbine, Generator		341,679			341,679	
Boom Truck, Radial Boom		54,399			34,916	
Prime Mover, D 3512		425,554			345,322	
Generator, KATO		136,112			98,792	
Generator, Stamford		129,828			71,267	
Prime Mover, DD2000		340,767			209,399	
Boom Truck, 1995 Digger Derrick		71,951			45,555	
Prime Mover, SF360TA		358,310			77,768	
Pangnirtung Plant		3,179,187			1,907,000	
Prime Mover, DD S2000			410,056			254,575
Generator, Stamford			238,926			129,127
Truck, 2005 Ford F150 C/C			44,775			39,584
Boom Truck, 1981 GMC 1 Ton Line Truck			19,834			19,834
Truck, 2007 Chevrolet 1500 4dr			23,996			11,025
Truck, 2002 F150 S/C 4x4			31,001			31,001
Wind Monitoring Tower			271,084			26,303
Total	**312,545**	**6,607,307**	**1,039,672**	**256,049**	**4,667,425**	**511,449**

URRC Findings:

79. The URRC notes the retirement of significant generating assets, some with material net book values. This means certain assets were retired well before the end of their average service lives (as estimated for depreciation purposes) primarily, as QEC states, due to reliability or operational reasons. In each of these cases QEC indicates there was no salvage value. The URRC is concerned the current asset accounting practices may not ensure accountability on the part of those responsible for asset retirements/dispositions to maximize the potential value of investments in retired or disposed plant.

80. QEC also notes the retirement of $3.2 million with respect to enclosure, transformers, accessory electrical equipment and part of the gensets purchased for temporary generation following the fire in Pangnirtung on April 2, 2015. QEC states these assets were fully amortized at the recommendation of the Auditor General (AG), because this was a temporary generation project, and the new plant is forecast to come in-service in 2017/18. The URRC is concerned the asset records may not keep track of assets that are prematurely amortized, leaving room for leakage of value from the system.

81. QEC states that it maintains an inventory of all assets and their location; when an asset is redeployed in another community the Corporation transfers the asset to the new plant in its accounting records. The transfer would be reflected in both regulatory and financial reporting. [URRC QEC 2-45] This statement however, is not consistent with Concentric Advisor's (Concentric) statement that a retirement rate analysis (mortality study of historic retirement transactions) could not be completed as the company did not have a sufficient level of historic retirement activity to provide meaningful results. [URRC QEC 2-43i)] If retirements, relocations or dispositions are duly recorded and tracked as QEC indicates, Concentric would have been able to carry out a retirement analysis.

82. The URRC considers that unless the activities related to retirement, relocation, disposal and premature amortization of significant assets are subject to appropriate procedural guidelines for accountability, controls and approvals as well as tracked within the regulatory and accounting records and are reflective of the physical inventory of assets by location and

vintage (through use of a geographical information system and asset management system), the controls over assets would largely be inadequate.

83. The AG in providing the basis for a qualified opinion respecting the 2016/17 financial statements states as follows with respect to management of certain non-financial assets as follows:

> Management has not implemented reliable count procedures and appropriate procedures to account for the usage of its spare parts and lubricants inventories, and I was not able to satisfy myself concerning these inventory quantities. As a result, I was unable to determine whether any adjustments might be necessary to reported non-financial assets as at 31 March 2017 and 31 March 2016. [2016/17 Annual Report p35]

84. In the URRC's view, while the apparent lack of controls over movement of spare parts was the subject of the AG's report, on a similar vein, the mechanisms in place to ensure accountability for retirements, dispositions and write-off of fixed assets including major assets such as generating units, transformers etc., have also not been demonstrated. Accordingly, it is recommended that QEC be directed to implement or augment mechanisms to ensure due accountability, controls and approvals for all activities including retirements, dispositions and write offs with a view to minimizing the potential for leakage of value arising from such transactions. QEC should report on this matter at the time of the next GRA.

5.4 WORKING CAPITAL

85. The following Table 4 shows the components of Working capital:

Table 4-Working Capital

	Cash Working Capital	Mid-Yr Customer Deposits	Mid-Yr Supplies Inventory	Fuel Inventory	Rent Prepaid	Insurance Prepaid	Total
	$000	$000	$000	$000	$000	$000	$000
2014/15 GRA	4403	-878	5819	9672	782	408	20206
2014/15 Act	4386	-1140	12718	10806	906	667	28343
2015/16 Act	4370	-1317	14040	9188	992	770	28043
2016/17 Prelim. Act	4349	-1386	14820	8018	1169	849	27819
2017/18 Fore	4195	-1405	14815	8018	1169	849	27641
2018/19 Fore	4287	-1423	14428	8018	1169	849	27328
Source: Schedule 6.4							

86. One of the major components of working capital is supplies inventory. QEC states, the growth in the inventory is related to several factors, including:

- Holding sufficient inventory to promptly address any distribution line issues (e.g., accidents requiring urgent pole replacement).
- Inflationary pressures increasing the cost of spare parts purchases. [URRC QEC 2-46a)]

URRC Findings:

87. The URRC is concerned by the 2.5 times increase in the level of supplies inventory since the last GRA in 2014/15. The Auditor General of Canada in providing the basis for qualified opinion respecting the 2016/17 financial statements states:

> Management has not implemented reliable count procedures and appropriate procedures to account for the usage of its spare parts and lubricants inventories, and I was not able to satisfy myself concerning these inventory quantities. As a result, I was unable to determine whether any adjustments might be necessary to reported non-financial assets as at 31 March 2017 and 31 March 2016. [2016/17 Annual Report p35]

88. In the URRC's view, a qualified audit report is a serious matter in any business setting, requiring immediate management attention to address the matter. Given the AG's concerns respecting supplies inventory level, the URRC is not convinced that QEC has provided sufficient justification for the 2.5 times increase in the supplies inventory level since the last GRA. Therefore, it is recommended that QEC be directed to implement or augment mechanisms to facilitate verifiability of physical inventory (quantities and values) and to take immediate steps to implement procedures and practices for efficient management of inventory levels and the exercise of appropriate controls over all inventory transactions. QEC is directed to report on this matter at the time of the next GRA.

5.5 AMORTIZATION

89. The proposed amortization expense is made up of three components, comprised of fixed assets amortization, loss on disposal of assets and amortization of financing costs as shown in the following Table 5:

Table 5-Amortization Expense				
	Fixed Assets Amortization	Loss on Disposal of Assets	Amortization of Financing Costs	Total Amortization Expense
	$m	$m	$m	$m
2014/15 GRA	8.6	0.0	0.3	8.9
2014/15 Act	9.4	0.0	0.3	9.7
2015/16 Act	10.8	0.7	0.3	11.8
2016/17 Prelim. Act	11.7	0.5	0.3	12.5
2017/18 Fore	9.3	0.4	0.3	10.0
2018/19 Fore	10.5	0.4	0.3	11.2
Source: Schedule 4.1				

Fixed Assets Amortization:

90. QEC states, the Depreciation Study calculates amortization rates using total original cost for each depreciable group of assets without removing any fully depreciated assets; for example, the proposed amortization rates in Table 1 of the Depreciation Study [URRC-QEC-1-12(a) Attachment 1] are calculated as total annual amortization amount adjusted for true up divided by total original cost of assets.

91. Concentric Advisors, QEC's depreciation consultants, noted that, over time, only the original cost will be recovered through tolls. Concentric indicated that during the completion of depreciation studies a test is made to determine if there is a variance between the actual booked accumulated depreciation reserve and the theoretical amount at that given point in time. Any variances are then trued-up over composite remaining life of the assets in order to ensure that only the original costs of the asset (adjusted for net salvage) is recovered through depreciation expense.

92. Concentric stated that a retirement rate analysis (mortality study of historic retirement transactions) was not completed as the company did not have a sufficient level of historic retirement activity for the study to provide meaningful results. However, an average service life analysis was completed by Concentric which included:
    - Review of peer information;
    - Discussion with management and operating staff; and
    - Completion of a physical site tour (in a previously completed study) which provided an opportunity to understand operating conditions in which the assets were installed. The above information provided Concentric with the ability to estimate an average service life for each account.

93. Concentric noted that as QEC continues to retire assets in future years, it may become beneficial to complete a retirement rate analysis. [URRC QEC 2-43i)]

94. Concentric states that the practice of expensing the costs of retirement associated with interim retirements is directed under the accounting standards followed by QEC. While Concentric views that the more traditional regulatory accounting approach of recovering the costs of retirement over the useful service life of the asset through a depreciation mechanism better complies to the matching principle, Concentric does recognize the complexities of managing the regulatory adjustments for a utility the size of QEC is overly burdensome.

95. Accordingly, Concentric states that it accepted the management policy decision to follow the accounting standard without making any regulatory adjustment as a reasonable approach in the specific circumstances of QEC. Concentric noted this same management policy is followed by a number of regulated Canadian Crown owned utilities.

96. Concentric also noted that any anticipated potential large expenditures related to terminal retirement costs associated with terminal retirement activity could be recorded as an Asset Retirement Obligation (ARO) with the annual accretion expense related to the ARO being included in the revenue requirement of the company. [URRC QEC 2-43c)]

URRC Findings:

Depreciation Method:

97. The URRC notes that the Depreciation Study calculates amortization rates using total original cost for each depreciable group of assets without removing any fully depreciated assets.

98. The URRC is concerned that the current approach would tend to overstate depreciation expense if assets that are no longer in use or the original cost of assets subject to insurance claims continue to remain in the regulatory accounting records. The URRC notes Concentric's caution that there are complexities involved in managing interim retirements for a small utility such as QEC. However, the URRC considers the complexities could be reduced if rather than recording interim retirements for components of plant, as under an Equal Life Group method, the retirement records could be maintained at an asset level (example: generating unit, transformer, switchgear etc.) as under a Direct Life Method. This Direct Life Method (DLM) of depreciation estimates the useful life of an asset (called the "average service life") and records depreciation on a straight line basis over that time period.

99. Accordingly, it is recommended that QEC be directed to bring forward at the next GRA a depreciation study and analysis whereby assets that are that are no longer in use and assets that are the subject of insurance claims, are removed from the regulatory accounting records, before applying the applicable depreciation rates.

Amortization of Reserve Surplus:

100. QEC states, as a result of the review of QEC's 2010/11 GRA, including the Depreciation Study (as of March 31, 2008), the provision for net salvage was removed from the calculation of the amortization rates and that the Reserve for Future Removal and Site Restoration amounts were rolled up into fixed asset accumulated amortization. [URRC QEC 43d)]

101. With respect to QEC’s proposal to removal of a provision for net salvage as part of depreciation rates, the URRC stated as follows in Report 2010-01, pages 54-55:

> The URRC has considered QEC's request to change the method for calculation of amortization rates whereby a provision for net salvage would no longer be included in the amortization rates and in the annual amortization provision. Rather, the actual expenditures/gains on net salvage and removal and site restoration costs will be expensed in the year incurred.
>
> The URRC notes three concerns with QECs proposal. First, the proposal may cause rate spikes in certain years, particularly if the cost of removal is high. For example, in URRC.QEC-21(f), QEC indicates the estimated costs of clean-up for the old Baker Lake plant site are in the range of $10 million. However, QEC indicates the liability ownership for the site has not been cleared between QEC/GN and Federal Government. If this expense were to be incurred by QEC, there will be a significant increase in the revenue requirement in the year incurred. Even if it is amortized over a number of years, it is still a significant increase. Avoiding the expense indefinitely may also not be prudent environmental stewardship on the part of QEC.
>
> Second, the recovery of negative salvage and removal costs from current customers, as opposed to all past generations of customers who were served during the service life of the asset, may be unfair from the point of view of intergenerational equity.
>
> Third, the funds required to pay for significant negative salvage and removal costs may not be available if these expenditures are to be expensed in the year they are incurred.
> In the URRC's view, QEC's proposal to change the method of amortization does not adequately address the foregoing concerns respecting QEC as a regulated utility. Accordingly, QEC is directed to continue to account for net salvage and future removal and site restoration expenses as part of the amortization rates and annual amortization expense for regulatory purposes. Under this approach, any expense/gain related to net salvage or site removal costs should be expensed to the relevant accumulated amortization account for regulatory purposes.
>
> The URRC notes the responsibility for environmental liabilities related to site clean-up may not rest entirely with QEC. Accordingly, QEC is directed to carry out an amortization study for the next GRA that provides a realistic assessment of future removal and site restoration costs. QEC is to include these costs and estimates for positive or negative salvage, by account, in the amortization rates.

102. The URRC notes from Table 2 of URRC QEC 12a) Attachment 1, that Concentric has estimated the difference between book accumulated depreciation and calculated accumulated depreciation to be $34 million as of March 31, 2016. Concentric has proposed to amortize this reserve surplus over the remaining life of the assets. The reserve surplus amortization for

March 31, 2016, was calculated to be $1.6 million and this amount is built into the depreciation rates proposed by QEC for 2018/19. The URRC estimates the reserve surplus amortization applicable to 2018/19 mid-year plant to be $1.9 million.

103. Upon being requested to separate the book accumulated depreciation as of March 31, 2016 into the net salvage reserve part and the service life reserve part, based on historical records and to provide the annual true up provision, based only on the service life reserve part, QEC stated the Reserve for Future Removal and Site Restoration amounts were rolled up into fixed asset accumulated amortization and the book accumulated depreciation as of March 31, 2016 cannot be separated into the net salvage reserve part and the service life reserve part. [URRC QEC 43d)]

104. The URRC notes from the URRC Report 2010-01 dated March 2, 2011, that there was a balance of $20.4 million accumulated reserve for net salvage at the time the salvage reserve was merged with the service life reserve.

105. The URRC also notes the following statement in QEC’s 2016/17 Annual Report, Note 16:

> **Liability for contaminated sites**
> The Corporation's activities are subject to various federal and territorial laws and regulations, such as the Environmental Protection Act of Nunavut and the Environmental Guideline for Contaminated Site Remediation - 2010, governing the protection of the environment or to minimize any adverse impact thereon. The Corporation conducts its operations so as to protect public health and the environment and believes its operations are in compliance with all applicable laws and regulations.
>
> The Corporation has identified 25 sites (2016 - 24 sites) where the concentration of petroleum hydrocarbons and other pollutants in the soil exceeds environmental standards. The contamination of certain of these sites occurred when other parties were responsible for the use of and/or held tenure to the sites.
>
> Management has estimated that remediation would cost approximately $38 million (2016 - $40 million). No environmental liability provision for remediation of these sites has been recognized in these financial statements as there is no legal requirement to remediate these sites; nor does management have the intention to remediate any of the sites. Going forward, an environmental liability provision for the remediation of any of these sites will be recognized if it is determined that public health is at risk.

106. The URRC notes that in the face of potential liabilities with respect to contaminated sites, it would not be fair or reasonable to refund through amortization of reserve differences those funds amounting to $20.4 million for accumulated reserve on net salvage collected from previous generations of customers, particularly since there is the potential for these funds to be required to meet liabilities on contaminated sites. Accordingly, for purposes of this report, the URRC will reduce the reserve surplus amortization as of March 31, 2016 by 60% ($20.4 million historical salvage reserve divided by $34 million surplus) so that only the estimated life portion of the reserve surplus would be amortized for 2018/19 and for all subsequent years until the next GRA when the matter may be reviewed.

107. In view of the reduction in the amortization of reserve surplus by 60% to recognize as part of depreciation expense only the estimated amortization of life surplus, for the purposes of this report, the URRC will increase the QEC proposed fixed assets amortization expense by $1.1 million (approximately 60% of $1.9 million included for reserve amortization for 2018/19). It is recommended that QEC be directed to recalculate for purposes of financial and regulatory accounting/reporting purposes the depreciation rates recognizing only 40% of the proposed reserve amortization.

108. Although the practice of expensing the costs of retirement associated with interim retirements is directed under the accounting standards followed by QEC, the URRC continues to be concerned that absence of a provision for negative salvage for regulatory purposes would not be consistent with prudent utility practice for the reasons stated in Report 2010-01 quoted above. In view of this, although the accumulated depreciation account has merged the net salvage reserve with the life portion for PSA accounting, for regulatory purposes the identities of the life portion and the salvage portion must be tracked separately; it is recommended that QEC be directed accordingly for the purposes of the next GRA. Further, for the next GRA, it is recommended that QEC be directed to address the appropriate treatment of a provision for negative salvage including future retirement and site restoration as part of the next depreciation study.

Loss on Disposal of Assets:

109. QEC included $407,000 with respect to loss on disposal of assets based on the average of three-year actual difference between historical records of original cost and accumulated amortization for the disposed assets.

URRC Findings:

110. The URRC does not consider loss on disposal of assets to be a revenue requirement item; rather under utility depreciation practice, any loss on disposal of assets should be reflected in the accumulated depreciation account. Accordingly, for the purposes of this report, the URRC has removed $407,000 for loss on disposal of assets from the amortization expense total and from revenue requirement for 2018/19.

Financing Cost Amortization:

111. The financing cost amortization of $0.249 million is the amount included in the revenue requirement in accordance with the URRC Report to the responsible Minister on QEC's 2004/05 GRA. These costs relate to the early payment of QEC's share of NTPC long-term debt, which amounted to $9.945 million. Because these financing costs resulted from the early repayment of NTPC debt and the Corporation's new debt incurred a lower interest rate, the Corporation incurred lower interest expenses than NTPC otherwise would have incurred.

112. In the 2004/05 GRA application, QEC requested to amortize the future benefit derived from the lower interest rate over the term of the debt for regulatory purposes. The amortization period was 20 years and the requested annual financing cost amortization was $0.497 million ($9.945 million / 20 years). In the 2004/05 GRA Report, the URRC considered 50% of these financing costs to be shareholder related based on the financial restructuring that occurred at the time and included an amount of $0.249 million for amortization of financing costs.

URRC Findings:

113. For the purposes of this report, the URRC accepts QEC's proposed amount for amortization of financing costs.

5.6 FUEL AND LUBRICANTS EXPENSE

114. Forecast fuel costs are based on forecast generation, (calculated as the sum of sales, line losses and station service), forecast fuel efficiencies (to convert generation volumes to liters of fuel) and the cost per litre of fuel.

115. 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.

116. 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.

117. 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 GN.
- 2018 forecast nominated fuel prices are based on the actual fuel prices announced by GN effective January 30, 2017.
- Summer 2018 bulk fuel prices to increase 3% over summer 2017 prices.

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

URRC Findings:

118. The URRC has reviewed QEC's calculations in Schedules 3.1, 3.2, 4.2.1 to 4.2.5 and, for purposes of this report, believes them to be appropriate.

5.7 NON FUEL OPERATING AND MAINTENANCE (O&M) EXPENSE

119. The components of non-fuel O&M expenses are set out below:

Table 6-O&M Expenses						
	Salaries & Wages	Supplies & Services	Travel & Accommodation	Site Restoration	Donations	Total
	$000	$000	$000	$000	$000	$000
2014/15 GRA	26465	22201	4682	161	-50	53459
2014/15 Act	29610	19618	4732		-41	53919
2015/16 Act	30386	21870	4391		-51	56596
2016/17 Prelim. Act	33273	24740	4708		-14	62707
2017/18 Fore	30376	22999	5213	161	-50	58699
2018/19 Fore	31287	23459	5317	161	-50	60174
Source: URRC QEC 1-7						

URRC Findings:

120. The URRC reviewed the O&M increases in responses to URRC QEC 1-7, 1-8 2-42. Part of the increase in salaries and wages in 2018/19 is due to the hiring of two FTEs, one a Policy and Planning Manager and a Policy Analyst. These positions would add strength to the Corporation's strategic planning, policies and procedures and corporate governance policies, among others. The URRC considers that adding personnel to policy areas would help QEC move towards its strategic objectives. Accordingly, for the purposes of this report, the addition of the two employees is accepted.

121. The URRC notes that the annual O&M provision for site restoration expense is $161,000, which is the same amount as in the 2010/11 and 2014/15 GRAs. The amount was estimated in the 2010/11 GRA as a 5-year average of actual site restoration costs. [URRC QEC 1-32a)]

122. In view of the URRC's decision to not amortize the estimated depreciation reserve associated with net salvage and to only amortize the estimated life portion of the reserve surplus as described in Section 5.5, the URRC considers that the site restoration expense should properly be charged against accumulated depreciation and more specifically against the salvage reserve. Therefore, for the purposes of this report, the URRC recommends that QEC's request to include $161,000 for site restoration expense be denied.

123. QEC also included a sum of $240,000 for plant decommissioning as part of O&M expenses. The URRC considers that plant decommissioning expense should properly be charged against accumulated depreciation and more specifically against the salvage reserve. Therefore, for the purposes of this report, the URRC recommends that QEC's request to include $240,000 for plant decommissioning expense be denied.

124. For the purposes of this report, the URRC accepts QEC's forecast of 2018/19 O&M expenses with a reduction of $161,000 for site restoration costs and a reduction of $240,000 for plant decommissioning expense.

5.8 RETURN ON RATE BASE

125. QEC proposed a 40% equity ratio in the capital structure and a rate of return on equity of 8.85% for 2018/19 based on the most recent approved generic ROE at 8.50% plus 35 basis points consistent with the most recently approved ROE approach for Northland Utilities (NWT) Limited.

126. 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.

URRC Findings:

127. The URRC notes that the last awarded generic rate of return on equity by the Alberta Utilities Commission [AUC] for distribution utilities with no income tax, was 8.30% and a capital structure of 40%. [Decision 20622-D01-2016 Dated October 7, 2016] The URRC considers a generic rate of return such as the AUC determined rate of return to be a neutral comparator for return awards and therefore appropriate for determination of a rate of return for QEC.

128. The URRC has considered the harsh environment and the isolated systems of QEC in relation to their potential impacts on the Corporation’s revenue variability, production risks and operational risks. While the harsh environment and isolated systems may impose a different kind of risk compared with other utilities with industrial revenues (for example) that can fluctuate with business cycles, the URRC is not convinced that QEC has more business risk overall so as to justify a higher rate of return than a generic rate. The URRC considered the Auditor General’s conclusion that QEC is not a rate regulated utility based on the finding the Corporation is unable to recover its costs without significant direct or indirect financial support from the GN and, this suggests, QEC’s exposure to business risks are being mitigated through GN support. This type of financial support does not exist in the case of private utilities such as NUL. The URRC estimates QEC’s business risks to be no higher than those of a generic non-taxable utility with a 40% equity ratio referenced in the AUC Decision. Accordingly, for the purposes of this report, the URRC determines QEC’s rate of return on equity to be 8.30% for 2018/19.

129. For the purposes of this report, the URRC concludes that it is appropriate to reduce the 2018/19 return on rate base by $548,000.

5.9 SALES AND REVENUE FORECAST

130. The following Table 6 shows the electricity sales and sales revenue from 2014/15 GRA to 2018/19 forecast:

Table 7-Sales and Revenues		
	Sales Volume	Sales Revenue
	MWh	$000
2014/15 GRA	172669	127227
2014/15 Act	170216	123465
2015/16 Act	173253	126973
2016/17 Prelim. Act	174529	127510
2017/18 Fore	176995	131104
2018/19 Fore	178851	132363
Source: Schedule 3.1		

131. QEC described the sales forecast method as follows at pages 3-14 and 3-15 of the Application:

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 usage per customer (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.

132. Communities with large increases in sales include Cambridge Bay, Gjoa Haven, Taloyoak, Rankin Inlet, Arviat, Igloolik, Naujaat, and Sanikiluaq; Communities with decreases in sales include Baker Lake, Pangnirtung, Cape Dorset, Resolute Bay, Kimmirut and Grise Fiord.

URRC Findings:

133. The URRC considers the sales forecast methodology and approach to forecasting of sales volumes and revenues to be reasonable. Accordingly, for the purposes of this report, the URRC accepts QEC's forecast of sales and revenues for 2018/19.

5.10 NON-ELECTRIC REVENUE

134. Forecasts of non-electricity revenues include revenues from joint use, miscellaneous charges, and project time and materials. QEC states, the 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 and 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. The following Table 7 shows the non-electric revenues since the time of the last GRA:

Table 8-Non Electric Revenue	
	$000
2014/15 GRA	3650
2014/15 Act	2311
2015/16 Act	2510
2016/17 Prelim. Act	2812
2017/18 Fore	2434
2018/19 Fore	2548
Source: Schedule 3.3	

135. QEC states, the Corporation's total non-electrical revenue forecast in 2018/19 of $2.548 million is consistent with the 3-year average actuals of $2.544 million from 2014/15 through 2016/17. Given that these revenues are extremely difficult to forecast and can fluctuate by significant percentages each year, QEC submitted that the total non-electrical revenue forecast appropriately reflects recent actual operating experience and is reasonable for ratemaking purposes. [URRC QEC 1-6c)]

URRC Findings:

136. The URRC notes one of the major contributors to reduction in other revenues since the 2014/15 GRA forecast is the reduction in time and materials (TMI) revenue from $1.64 million in 2014/15 to $0.74 million forecast in 2018/19. The URRC notes QEC's explanation that TMI projects are undertaken at a customer's request, or if a project was undertaken to recover damage caused by a third party; for the actual years since the 2014/15 GRA, TMI project volumes have been significantly lower than 2014/15 forecasts reflecting lower number of customer requests for small projects.

137. Given the above explanation for decline in time and materials revenue, for the purposes of this report, the URRC accepts QEC's overall forecast of non-electric revenues.

5.11 SUMMARY OF ADJUSTMENTS TO REVENUE REQUIREMENT

138. The following Table 9 shows the revenue requirement and revenues approved by the URRC:

	Table 9-Revenue Requirement as Adjusted by URRC		
		2018/19	2019/20
		$000	$000
1	Revenue Requirement as Proposed	134047	
2	Adjustment for Rate of Return on equity	-548	
3	Adjustment Capital Cost of Grise Fiord Plant	-229	
4	Loss on disposal	-407	
5	Site Restoration Expense	-161	
6	Plant Decommissioning	-248	
7	Reversal of Proposed Annual Provision for True up	1100	
8	Sub total of adjustments	-493	
9	Revenue Requirement as per the URRC	133554	133554
10	Revenue Offsets	-2548	-2548
11	Rate Level Revenue Requirement	131006	131006

139. The above Table 9 shows a URRC determined revenue requirement of $133.554 million for 2018/19, which is a reduction of $493,000 from the revenue requirement proposed by QEC. The URRC recommends that the revenue requirement of $133.554 million be approved. In Section 6.2, the URRC will recommend that QEC be directed to propose rates that would recover the URRC determined revenue requirement.

6.0 COST OF SERVICE STUDY AND RATE DESIGN (PHASE II MATTERS)

6.1 COMMENTS ON RATE CHANGES

140. Community meetings were held in the winter respect the GRA and the proposal for Nunavut wide rates. QEC personnel and Members of the URRC attended the meetings. In addition to comments provided by parties at community meetings written comments were received by February 2, 2018.

141. There was support for and against the change to Nunavut wide rates. Those in favour of the territory-wide rates generally only stated their support for the proposal. Those against the

territory-wide rates often expressed the concern that rates in communities should reflect costs and that costs were not the same in all communities. Cited cost variance included population density, transportation costs, temperature and daylight differences.

142. One party providing written comments stated, while the change may be necessary, more information and public consultations are required in order to better understand the impact to all communities over the six year period.

143. A common issue or concern expressed was whether the subsidy would compensate for any changes in rate structure. QEC responded that this was not an issue for QEC but for the GN.

URRC Findings:

144. The URRC will take the above comments into consideration in dealing with QEC's rate change proposals.

6.2 RATE CHANGE PROPOSALS

145. The Application also requests approval of a revenue phase in mechanism whereby the customer impact from termination of the 5.41¢/kWh FSR rider would be phased in over a period of 2 years (2018/19 and 2019/20). Further, as part of the Phase II application QEC requested approval of rates, effective April 1, 2018 and April 1, 2019, that would gradually move community based rates towards recovery of Nunavut wide cost of service; QEC requested that the phase in period be completed in 6 years, commencing in 2018/19.

146. The Corporation's rate design objectives for the 2018/19 GRA are set out in the Application page 8-12 and 8-13 as follows:

- Rates must be set to recover revenue requirement
- Make progress toward Territory-wide rate zone (levelized rates).
- Move toward 95-105% revenue-cost coverage ratios for each rate class
- Phasing-in rate increase / decrease

i. Revenue Requirement Phase-in: 7.6% overall rate increase to recover the 2018/19 revenue requirement. Proposed to phase-in the revenue lift required to achieve the full 2018/19 revenue requirement over two years – 2018/19 and 2019/20 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.

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.

- Phasing-in elimination of Government/Non-Government rate class distinction.

147. QEC described the steps taken to design domestic, commercial and street lighting rates as follows at pages 8-14, 8-15 of the application:

> 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 focusing 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.

URRC Findings:

Current Rate Changes:

148. The URRC has considered the rate realignment proposals and notes that the community that would see the maximum increase in each of 2018/19 and 2019/20 would be the Iqaluit domestic customers (about 18.5% increase over two years made up of 9.9% in 2018/19 and 8.6% in 2019/20) and Iqaluit commercial customers (about 20.6% increase over two years made up of 12.0% in 2018/19 and 8.6% in 2019/20). Given that the Nunavut Electricity Subsidy Program (NESP) subsidizes rates for eligible consumption in all Nunavut communities is calculated at 50% percent of the Iqaluit base rate, the significant increases in rates for Iqaluit means corresponding increases in customer bills in other communities as well.

149. While the URRC supports the proposed move towards rates for all communities based on Nunavut wide cost of service, in the URRC’s view, the maximum rate realignment increases should be limited to 3% in each of 2018/19 and 2019/20 in order to preserve rate stability for all customers, at this time. The URRC will therefore direct QEC to redesign rates based on this determination.

150. The following Table 10 shows the revenue requirement as determined by the URRC and the corresponding shortfall:

Table 10-Revenue Requirement as per URRC and Revenue Shortfall			
		2018/19	**2019/20**
		$000	$000
1	Rate Level Revenue Requirement per URRC	131006	131006
2	Energy revenue at existing base rates	125841	
3	Rate reduction to align existing rate revenue with revenue requirement	-864	
4	QEC proposed Rate reduction for revenue phase in and rate realignment	-3660	
5	Energy Revenue as Adjusted	121317	
6	Customer and demand charge revenue	6522	
7	Sales revenue proposed by QEC	127839	127839
8	Rate Increase for Revenue Phase in		3167
9	Revenue deficiency	3167	0

151. The URRC recommends that QEC be directed to file within 10 days of this report revised rates to recover the revenue requirement determined by the URRC. In 2018/19, which is a transition year, the rates should be designed to recover revenues of $127.839 million and, in 2019/20 the rates should be designed to recover the rate level revenue requirement of $131.006 million. The rates effective April 1, 2018 for 2018/19 and, rates effective April 1, 2019 for 2019/20 should be designed using the following steps:

For 2018/19:

Step 1:

152. For 2018/19, QEC has proposed to reduce existing base energy rates by $864,000 [Table 10, L3] to reflect the QEC proposed 2018/19 revenue requirement. Since this is QEC's estimate of excess revenue in 2018/19, the reduction should be in proportion to existing base energy rate revenue. The URRC calculates this adjustment to be 0.6865% (864,000/125,841,000).

Step 2:

153. QEC has proposed to reduce existing base energy rates by $3.66 million [Table 10, L4]; since this adjustment relates to a per kWh adjustment arising from the 5.41¢/kWh FSR, reduce existing rates by 2.046¢/kWh ($3.66 million divided by energy sales of 178,851 MWh).

Step 3:

154. Following Steps 1 and 2, arrive at a total energy revenue of $121,317,000.

Step 4:

155. Give effect to a rate realignment increase based on the lower of 3% or one sixth (representing 6-year transition) of the difference between full cost recovery and base rate level. For example, if the base rate level after steps 1 and 2 is 63¢/kWh and if the cost of service rate is 78¢/kWh, then choose the lower of 3% or 4% (the 4% reflects an equal transition over 6 years, of the percentage difference between 78¢/kWh and 63¢/kWh). Allocate the resulting revenue to higher cost communities in proportion to the degree of deviation from cost of service-based energy rates; the rate realignment energy revenue increases and decreases should zero out.

For 2019/20:

Step 1:

156. Increase 2018/19 base energy rates by the revenue shortfall of $3.167 million. This would translate to an increase of 2.61% ($3.167 million/$121.317 million).

Step 2:

157. Give effect to a rate realignment increase based on the lower of 3% or one fifth of the difference between full cost recovery and base rate level. For example, if the base rate level after step 1 and is 65¢/kWh and if the cost of service rate is 78¢/kWh, then choose the lower of 3% or 4% (the 4% reflects an equal transition over the remaining 5 years, of the percentage difference between 78¢/kWh and 65¢/kWh). Allocate the resulting revenue to

higher cost communities in proportion to the degree of deviation from cost of service=based energy rates; the rate realignment energy revenue increases and decreases should zero out.

Future Rate Changes:

158. In the URRC's view, rate realignment increases and related decreases beyond the 2018/19 and 2019/20 years would not be reasonable for two reasons. First, the URRC notes, QEC is facing significant overall cost pressures due to significant plant additions in the years following 2018/19 and 2019/20; therefore, combining such cost driven increases with rate realignment increases could result in unacceptable levels of rate increases which may be harmful for investment and economic growth in Nunavut; second, in the URRC's view there may be other approaches to rate realignment which may mitigate non-Government customer rate increases in lower cost communities while at the same time non-Government rates of high cost communities are reduced directionally toward Nunavut wide rates. This means a greater share of the burden of realignment would be borne by Government customers; the economic rationale for this approach would be to ensure, unacceptable levels of rate increases which may be harmful for investment and economic growth in Nunavut, are mitigated. In this regard, the URRC notes QEC's views on the possibility of moving Government customer rates towards a higher revenue to cost ratio relative to non-Government rates as follows:

> QEC's existing rates (including fuel rider) for government domestic customers in nine communities, including major centres like Iqaluit, Rankin Inlet, Cambridge Bay and Baker Lake are lower compared to the territory-wide COS rates. The government rates for commercial customers in seven communities are lower compared to territory wide COS rates. These communities account for approximately 65% of domestic and commercial sales. In order to derive a benefit from higher than average cost government rates, government customers in these communities would need to see higher than proposed rate increases. [URRC QEC 2-48]

159. And further:

> Such a rate option could be considered if directed by the Government of Nunavut, but would require substantially higher rate increases for government customers in the larger communities than is currently proposed. [ibid]

160. Accordingly, the URRC recommends that QEC be directed to examine an approach to rate realignment including the adoption of higher revenue to cost ratios for Government customers with a view to minimizing the harmful effects of high rate increases for investment and economic growth in Nunavut, at the next GRA.

6.3 COST OF SERVICE STUDY

161. QEC submitted a Cost-of-Service Study (COSS) which went through a six step process as outlined in Appendix C of its Application. The steps included allocation of costs to different functions, classification of the functionalized costs to customer, demand or energy categories and allocation of classified costs by rate class. QEC notes that the results indicate that, if rate increases were applied on an equal-percentage-across the-board basis, the domestic rate class Revenue to Cost Coverage (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. And the Streetlighting customer class would have an RCC ratio of 83.7%, suggesting that this class should receive higher than average rate increases.

162. The results of the COSS 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.

URRC Findings:

163. For the purposes of this report, the URRC accepts the proposed cost of service study.

6.4 TERMS AND CONDITIONS OF SERVICE

164. 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. [Application, pp 9-1, 9-2]

165. QEC states, 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. QEC states, typical customers impacted by this clause would be Three Phase Commercial Customers with unbalanced loads. Three Phase Commercial Customers with older model electric motors and or pumps connected to their service may also be affected. [URRC QEC 1-20]

URRC Findings:

166. The URRC recommends approval of the proposed changes to Terms and Conditions of Service. The URRC expects QEC to duly notify customers who may be impacted by this change and give them a reasonable amount of time to comply with the requirements for power quality.

7.0 OTHER MATTERS

7.1 REPORTING AND OVERSIGHT

167. Rate Setting Guidelines Concerning the Procedures and Practices of the Utility Rates Review Council, Section 2, dealing with Monitoring and Oversight provides as follows:

> A regulated utility may be requested by the Review Council to file with the Council periodic reports concerning its affairs, earnings, operations, service levels or any other matter that would assist the Review Council in discharging its responsibilities under the Act.

URRC Findings:

168. The URRC notes that the Finance and Audit Committee assists the Board in meeting its oversight and financial responsibilities and accountabilities to the Corporation and its stakeholders. The URRC is concerned that where multimillion dollar contracts are awarded for new power projects the established policies for due diligence work is not being followed.

169. The URRC cannot carry out its mandate effectively, unless there is assurance from an independent oversight body that the underlying systems provide adequate checks and balances for transaction to occur in an economically efficient way.

170. The URRC recommends that the Finance and Audit Committee provide a report annually (until the next GRA) to the responsible Minister setting out its independent assessment of the effective implementation of the requirements set out in the capital planning manual. [URRC QEC 33c)]

7.2 RENEWABLE ENERGY

171. At the Community meetings, participants asked about renewable energy programs. They asked either on the generation side (wind, solar, hydro) or on the conservation side. The overriding concern relates to costs and how to reduce costs.

172. One of the written submissions stated, instead of paying a large amount of money replacing old generators in small communities, QEC should invest in renewable clean energy instead. In response to the above comment QEC stated as follows in its February 23, 2018 submission:

> QEC notes that it currently researches emerging alternative energy technologies in Nunavut and has implemented pilot projects and programs to promote renewable energy generation in Nunavut:
>
> - QEC successfully commissioned a 2 kW solar panel demonstration project at the Iqaluit power plant. QEC has been working with Natural Resources Canada (NRCan) on this demonstration project which will help QEC on future solar panel projects. Eleven solar panels have been integrated to the grid and have been feeding power to the city since March 2016.
> - With support from Indigenous and Northern Affairs Canada's (INAC) ecoENERGY program, QEC completed the first phase of a desktop study to assess the viability of wind power generation in all 25 communities in March 2016.
> - QEC has initiated a Net Metering program allowing customers who install their own solar panels and renewable power generation systems to sell power to QEC that is surplus to their own requirements.
>
> It is important to note however that 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.

URRC Findings:

173. The 2016/17 Annual Report notes that the Alternative Energy Committee provides recommendations to the Board regarding the viability of alternative or renewable energy technologies in the North. The committee also provides input on financing options and financing sources for development, demonstration projects, research initiatives, collaboration opportunities, and supportive and overlapping mandates of other organizations.

174. The URRC in Report 2017-04 dated November 30, 2017 respecting the Kugluktuk replacement plant project permit stated:

> The URRC considers the sizing of units performing different roles such as base load, peaking, spinning reserves etc. need to be optimized under a forward looking planning

environment that contemplates cost effective integration of renewables and storage. The URRC has not seen any evidence from QEC that the configuration of units was appropriately calibrated to minimize overall costs of the plant including capital and operating costs. [Paragraph 31]

175. The URRC expects the establishment of the Alternative Energy Committee would provide a greater degree of coordination between capital project design, planning and development and cost-effective integration of renewables into the system.

7.3 SERVICE QUALITY AND RELIABILITY

176. QEC's responses respecting customer satisfaction, worker safety and reliability are set out in URRC QEC 1-21.

Customer Satisfaction:

177. QEC states it has been undertaking customer satisfaction surveys at regular intervals since 4 October 2015; responses have been generally positive and have been showing continued improvement over time. For example, customer service ratings in the survey have improved from Q1 2016 (59%) to Q4 2016 (71%).

178. QEC states that it reviews customer comments and considers where there may be opportunities to improve processes and service to customers. Examples of such reviews initiatives include:

1. Billing: QEC states it is in the process of introducing e-billing, which is currently being tested at employee's level (i.e., QEC staff started receiving e-bills as a pilot introduction to identify any delivery issues that may need to be addressed before roll-out to all customers). E-billing can help reduce the lag time in customers receiving their bills, particularly during winter.

2. Call Centre: QEC states it has a limited number of staff who serve a population of approximately 37,000 people across the Territory with three time zones. It is simply not feasible to have live agents available to all customers at all times. As such depending on the timing of the call (e.g., rush time; after hours; time zone difference affecting start,

lunch time, and end of workday), customers may be put in queue in order to speak with live agent. QEC states it has made other options to contact QEC available to its customers, including:

a. Leaving a message explaining their issue and related QEC specialists will contact them back.
b. Emailing QEC at customercare@qec.nu.ca.
c. Contacting by fax at 1-867-793-4225.
d. Reaching QEC in person in regional offices in Baker Lake, Iqaluit, Cambridge Bay, and Rankin Inlet.
e. Reaching QEC by regular mail.
f. Contacting QEC by submitting a direct message on QEC's website at http://www.qec.nu.ca/content/contact-us.

Worker Safety:

179. With respect to worker safety QEC states it has invested a significant amount of time developing an in-house Supervisors Safety Course that is mandatory for anyone who is responsible for overseeing other personnel.

180. QEC states, other steps that have been taken to improve worker safety include:

- Developing an in-house Utility Work Protection Code (WPC), which is a permit and lock based system that ensures that equipment being worked on is de-energized, isolated and/or grounded.
- Developing a comprehensive safety manual that contains 18 essential elements of an effective safety program.
- All new hires undergo a safety orientation and are provided with the QEC Safety Rulebook at the time of hire. Additionally, they are required to attend appropriate safety training such as WPC, Fall Prevention, Workplace Hazardous Materials Information System (WHMIS), Confined Space, Arc Flash, Cranes and Rigging etc. prior to performing any work.
- QEC is in the process of completing arc flash studies throughout the territory for all power plants (including older ones).
- This year there will be further development of Standard Operating Procedures and Safe Work Practices.

- Changes have been made to the Contractor Safety Program with an emphasis on Project Safety Planning.
- Operations staff perform a tailboard meeting (pre-work safety meeting) daily before any medium-high risk work starts and then another one if the jobs changes scope at any point during the day. Health, Safety and Environment (HSE) also conducts monthly safety meeting with all of QEC's Operations group and quarterly safety meetings for all office staff.

181. The following tables show QEC's expenditures on safety budgets:

Table 1: Safety Training Costs ($000)

Safety Training /online services	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
MSDS Online	2.9	2.9	2.9	2.9	2.9	2.9
First Aid Training package/manuals			2.8	2.8	38.6	
Fall Arrest Protection Training/ TTT				3.5		
Hearing Conservations Training HS			7.0			
Electrolab training material			0.4			
Online Orientation			11.0	6.0	5.0	5.0
Electrical Safety Training Course					70.0	70.0
NSA Supervisors Course				18.9	0.3	
Overhead Crane TTT				0.9		
Ergonomics Training HS		7.0				
CSSE Conference	35.0	35.0	28.0	35.0	35.0	35.0
JOHSC AGM	25.0	25.0	-	25.0	25.0	25.0
Lineman Annual Refresher Training	50.0	50.0	50.0	50.0	50.0	50.0
NAOSH Week	10.0	10.0	10.0	10.0	10.0	10.0
COR limited scope Audit	3.4	0.6	0.6	3.4	6.0	12.0
Operator Training	500.0	-	-	238.5	238.5	238.5
Total	**626.3**	**130.5**	**112.8**	**396.8**	**481.2**	**448.4**

Table 2: Safety Equipment Costs ($000)

Safety Equipment	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
AED			18.2		11.6	-
Inspection Stickers for Eletrical equipment					1.3	
Confined Space Rescue Equipment				3.1		
QEC Safety Rulebooks				6.4		
Gas Detectors				2.3		
Lockout devices				5.0		
Hearing testing equipment				3.5		
Arc Flash protective equipment		3.6	3.2			
Harness and Ladder System IQ					3.7	
Hard Hat with Miners Lamp					1.1	
Miners lamp					3.6	
Backing in Signs					2.6	
Audiometric sound level meter					1.3	
Repirators and fliters		0.8	3.0		3.5	
First Aid manuals			1.5		2.8	
Fence warning signs/voltage					2.0	
Eletrical rescue hook					0.4	
Ergonomic office equip			3.8			
Specialized PPE						50.0
Other PPE	15.0	15.0	15.0	15.0	15.0	15.0
Crane and Lifting Devices Inspection	32.4	32.4	32.4	32.4	32.4	324.0
Other						20.0
Fall Arrest	45.0		1.4	211.0	2.2	
Total	**92.4**	**51.8**	**78.4**	**278.7**	**83.6**	**409.0**

The URRC notes an error in the $324,000 number included in Crane and Lifting Devices Inspection costs reflected in Table 2 above.

Reliability:

182. The following table shows the reliability indices for each of the communities:

Table 3: SAIDI and SAIFI Statistics by Community

	2014/15		2015/16		2016/17	
	SAIDI (h)	SAIFI	SAIDI (h)	SAIFI	SAIDI (h)	SAIFI
Cambridge Bay	4.29	9.23	5.55	7.07	3.27	2.20
Gjoa Haven	0.81	2.90	2.70	4.65	1.70	4.80
Taloyoak	0.83	3.58	0.07	0.42	9.85	6.76
Kugaaruk	0.00	0.00	1.48	4.00	0.08	1.00
Kugluktuk	0.57	1.00	0.25	2.46	1.75	2.00
Rankin Inlet	4.67	5.70	0.55	3.26	2.73	3.69
Baker Lake	1.57	11.71	6.92	6.29	17.78	3.43
Arviat	3.30	5.60	1.02	2.74	0.89	3.56
Coral Harbour	1.43	6.35	2.33	5.15	0.79	1.11
Chesterfield Inlet	0.10	0.63	0.00	0.00	0.25	3.00
Whale Cove	6.05	11.96	25.10	24.08	1.22	6.46
Repulse Bay	19.76	12.42	13.41	14.42	2.68	2.00
Iqaluit	2.30	9.94	3.17	6.51	2.94	8.76
Pangnirtung	5.82	12.79	21.47	11.71	2.24	6.45
Cape Dorset	2.51	12.26	6.12	12.47	2.72	4.95
Resolute Bay	3.12	12.57	11.49	25.94	4.31	10.38
Pond Inlet	7.51	2.67	1.07	3.88	0.70	8.05
Igloolik	0.74	8.78	0.22	2.98	0.12	1.01
Hall Beach	5.70	27.97	0.90	9.10	0.28	4.12
Qikiqtarjuaq	4.96	6.72	4.74	6.72	3.83	16.53
Kimmirut	0.21	2.36	1.26	11.02	23.88	5.13
Arctic Bay	3.99	7.78	2.34	6.20	5.07	4.67
Clyde River	1.56	5.00	6.97	5.82	2.21	7.23
Grise Fiord	4.52	2.92	12.05	13.87	12.08	17.71
Sanikiluaq	8.79	23.92	18.56	19.10	8.71	15.85
Average	3.28	8.59	4.59	6.80	3.90	6.00

183. QEC states, minimizing number of outages to provide reliable service has always been one of QEC's top priorities and QEC continues to invest in infrastructure upgrades to improve reliability performance. QEC states, outage statistics provided on page 10-13 of the Application show that QEC performed better than the average of the other northern utilities for both System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) in two out of the last three years.

184. QEC states, the key factors in the years where reliability indicators were poorer than the average of northern utilities include:

a. 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.

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

URRC Findings:

185. The URRC notes the developments in the areas of customer satisfaction, worker safety and reliability and accepts the information for the record.

7.4 ADVANCED METERING INFRASTRUCTURE (AMI)

186. QEC added $1.637 million to rate base in 2016/17 for an AMI smart grid project which includes 4000 Automatic Meter Reading (AMR) meters installed in Iqaluit. The total cost of the project is $2.9 million and QEC received a Federal contribution of $1.3 million towards this project.

187. QEC's 2016/17 Annual Report states, the Smart Grid or AMI project was implemented under the Natural Resources Canada ecoENERGY Innovation Initiative. The smart grid is a modern electrical communication network that allows real time measurement of customer energy consumption, monitors energy flows and adjusts to changes in energy supply and demand. QEC states, this technology has enabled the Corporation to respond to outages more efficiently, enhanced its billing capability through automatic remote meter reading and improve service reliability. In addition, QEC states the Smart Grid technology will allow for the integration of renewable energy systems with the Iqaluit grid and will enable QEC to implement net metering initiative using the bi-directional feature associated with the smart meters.

188. QEC states, with the conversion to AMI metering in Iqaluit, all commercial customers in the city now have active demand meters; in the near future QEC will assess opportunities to implement AMI conversions in other communities subject to a review of benefits. QEC states it is also working on initiatives to ensure all commercial customers in smaller communities are provided with demand meters. [URRC QEC 1-19b)]

URRC Findings:

189. The URRC notes the developments in the area AMI and AMR and accepts the information for the record.

8.0 URRC RECOMMENDATIONS TO THE RESPONSIBLE MINISTER

190.0 Based on the above Report the URRC recommends as follows:

1.0 The URRC Recommends approval of a revised revenue requirement of $133.554 million for 2018/19, which is a reduction of $493,000 from the revenue requirement proposed by QEC.

2.0 That the Responsible Minister direct QEC as follows:

a) That if, following approval of a major project, the projected costs for the project exceed the amount approved by the Minister by more than 25% or $5 million, whichever is greater, QEC be directed to file an amended MPPA with the Minister.

b) To reduce the actual costs of the Grise Fiord plant to be included in rate base for future rate applications, in a manner consistent with the forecast reduction of $5.1 million as shown in Table 2A.

c) To implement or augment mechanisms to ensure due accountability, controls and approvals for all activities including retirements, dispositions and write offs with a view to minimizing the potential for leakage of value arising from such transactions. QEC to report on this matter at the time of the next GRA.

d) To implement or augment mechanisms to facilitate verifiability of physical inventory (quantities and values) and to take immediate steps to implement procedures and practices for efficient management of inventory levels and the exercise of appropriate controls over all inventory transactions. QEC to report on this matter at the time of the next GRA.

e) To bring forward at the next GRA, a depreciation study and analysis whereby assets that are no longer in use and assets that are the subject of insurance claims, are removed from the regulatory accounting records, before applying the applicable depreciation rates.

f) To maintain the separate identities of the life portion and the salvage portion of accumulated depreciation for regulatory purposes, for the next GRA; URRC requests that QEC address the appropriate treatment of a provision for negative salvage including future retirement and site restoration as part of the next depreciation study at the next GRA.

g) To file within 10 days of this report 2018/19 rates, effective April 1, 2018 and 2019/20 rates, effective April 1, 2019, using the steps set out in Section 6.2.

h) To examine an approach to rate realignment including the adoption of higher revenue to cost ratios for Government customers with a view to minimizing the harmful effects of high rate increases for investment and economic growth in Nunavut, and report that at the next GRA.

3.0 The URRC recommends that the Finance and Audit Committee provide a report annually (until the next GRA) to the responsible Minister setting out its independent assessment of the effective implementation of the requirements set out in the capital planning manual. [URRC QEC 33c)]

4.0 The URRC recommends approval of the proposed changes to Terms and Conditions of Service.

191. Nothing in this Report shall prejudice the URRC in its consideration of any other matters respecting QEC.

ON BEHALF OF THE

UTILITY RATES REVIEW COUNCIL

DATED MARCH 26, 2018
ANTHONY ROSE
CHAIR

APPENDIX 1
2017/2018 URRC GRA PUBLIC HEARINGS

<u>December 4: Rankin Inlet, no attendance.</u>

<u>December 5: Baker Lake, 11 attendees.</u>

<u>PARTICIPANT:</u> The MLA expressed concern that public housing tenants had an effective rate (due to GN subsidy) that was much lower than the rates borne by residential homeowners. Their wasteful habits were encouraged by the high subsidization by the GN. He pointed out that paying "higher rates", private home owners were forced to minimize consumption by practicing energy saving measures. He felt the two rates were unfair and that private home owners should be subsidized the same as public housing customers.

He also felt that commercial customers should pay the same rates as residential, thereby lowering the burden on the residential customer group.

He felt these two factors were a disincentive to owning your own home. He felt that all customers should pay the same rate.

<u>QEC:</u> QEC explained that the two customer classes pay different rates because the costs to serve each group differed. If the costs to serve each group was the same, then there would not be a need for different rates.
QEC also explained that subsidies were determined by the GN and not by this regulatory process.

<u>PARTICIPANT:</u> The MLA expressed concern that QEC staff in Baker Lake live to a different standard than other home owners due to their employment and benefits. Private homeowners incur high rates regardless of their benefits package and whether (or not) they have steady income.

He also restated that the rates that public housing tenants face should go up as the current burden to private homeowners is unfair/inequitable. He felt those living in public housing should be given some sort of incentive to reduce consumption like private homeowners need to.

<u>PARTICIPANT:</u> Expressed concern that the people need education/training to learn ways to use electricity more effectively. As it stands now, public housing residents pay so little, that heat and energy is being wasted by windows left open during cold. The people need to be taught how to conserve.

<u>PARTICIPANT</u>: Expressed concern that there wasn't a common rate for all classes of customers. He also supported the idea of public housing residents paying the same rates as private home owners or that the private homeowners deserved a larger subsidy. He also thought it was important that consumers were educated on how to conserve consumption.

Homeowners pay the "full cost" regardless of their economic situation unlike public housing tenants.

He appeared to support Nunavut wide rates as he said that rates must be fair to all communities.

QEC: First to the matter of training and education, QEC indicated that the company is working on programs to assist in understanding the efficient use of electricity. QEC also indicated that they are starting to work on education in conjunction with Nunavut Housing Corp (NHC) and the Climate Change Secretariat. Since the spring of 2017 they have been putting efforts into a Facebook page that can be shared.

QEC also attempted to explain that the subsidy program was under the GN's authority and discretion and that it really had nothing to do with the GRA. Also, that the GN controls and administers the subsidy programs, not QEC nor via the GRA process.

QEC did indicate that it would be reviewing the subsidy program with the GN and would pass these concerns along.

PARTICIPANT: He felt that the large number of new public housing units (100+) and the energy practices of public housing tenants causes higher costs for all other customers. He indicated that all residential customers should have access to the same subsidy program benefits.

He also expressed real concern over the cost of the new plants being installed as replacements to old infrastructure. Bringing these new plants into rates was going to be costly.

Man: Asked about the impact of the proposed carbon tax on electricity rates and expressed concern that fuel costs are likely to rise after the last years of fuel cost reductions.

QEC: The proposed carbon tax will impact all QEC customers and make everything more expensive overall but the GN and QEC are discussing this with the Federal Government to see how it might be mitigated. The mechanics of the FSR was also explained to address fuel cost fluctuations versus the cost used when setting rates.

PARTICIPANT: He felt that educational handouts about using energy more conservatively were a waste and also that there was very limited access (and no available subsidies) to secure equipment like solar panels on an affordable basis along with shipping and installation.

He asked whether QEC had a standard design for replacement power plants that would minimize their costs.

He also asked about why more district heating was not offered to customers using the waste heat from generating electricity.

QEC: With respect to power plant design, each community is unique so the company can only have common standards for design, not a standard power plant. It was also pointed out that GN procurement practices require tendering to suppliers so that standard power plant equipment would be unlikely. However, the designs are to a common standard.

Residual heat projects are not part of the GRA process and must be funded separately. So far, the Government of Canada has assisted, but capital funding is difficult to get. The economics of residual heat projects are poor and special low cost financing is necessary.

PARTICIPANT: He stated that meters don't differentiate between customers and that as a result commercial and residential rates should be the same.

QEC: Tried to explain the Cost of Service model again.

PARTICIPANT: Expressed concern that just when employees get an increase in wages, things like this GRA come along and take away the benefit received. Expressed concerns and desire to have an impact on what happens with the GRA.

PARTICIPANT: Requested that QEC provide him with the total cost of refunds by way of the FSR that were refunded over the past two years.

QEC: This information will be provided.

December 6, 2017 Kugluktuk, 7 attendees

PARTICIPANT: How did you come up with the rates shown?

QEC: Our costs have risen such as employee costs, contractor rates. Yet we haven't had an increase since 2014. We applied our rates to our expected sales and determined there was a shortfall. This shortfall must be recovered from forecast sales.

Different community rates were established by NWT Power and we have typically applied a % increase. Part of our proposal includes a change to a common rate across all communities.

PARTICIPANT: Public housing units are in very poor condition and have leaky doors and windows. They are drafty, overcrowded and have often never been renovated. How can this be resolved?

QEC: We acknowledge the energy efficiency differences between aging homes of different vintages. QEC has and is developing programs to help people better understanding how to reduce energy losses. We are working with the GN, Climate Change Secretariat and the Nunavut Housing Corp on a joint program focusing on teaching people how to use energy wisely and efficiently. (RGL comment: We should consider giving a recommendation that QEC work with the Housing Corporation to better maintain public housing so as to minimize energy loss.)

PARTICIPANT: There is a construction boom in the community of commercial facilities. Will increased growth in commercial customers impact residential rates?

QEC: No, there are separate rates for residential and commercial customers. The differences correspond to the cost of providing service for that specific customer group. Commercial costs are not going to be transferred to residential consumers.

PARTICIPANT: Yes, rates appear to go down for Kugluktuk now, but won't they rise again?

QEC: Yes, as inflation and growth cause our costs to increase in the future, these costs must be recovered, and will increase rates. In the short term, though, Kugluktuk's rates are going down. (RS comment: While this is exactly what Bruno said, I'm not sure that it's entirely correct to make this statement when you consider the effective (post-subsidy) rate and the fact that the GN has not confirmed what might be done with the subsidy.)(NC comment, also when rates become standard across NU, surely that would be more economical for QEC to administer).

Meeting with Kugluktuk Town Council, December 6, 2018

CAO: Is the new proposed power plant in the rates?

QEC: No, not until it is constructed and has been put into operation, i.e. used and useful.

Councillor 1: Are all new costs not already spread out across all Nunavut customers.

QEC: There are three options that we have considered for rates:

a. Status quo. Increase current community rates by the percent increase in our revenue requirement. This has been the historic way to recover rate increases. (Differing community rates were established historically under NWT Power.)
b. Move to a common harmonized rate that is the same in all Nunavut communities. Some communities will experience increases to their rates and some will experience decreases.
c. Use community specific rates where the costs of providing service in each community are recovered from the customers in those individual communities.

Our proposal is option B which will achieve a number of objectives as outlined in our presentation.

Councillor 1: Will the rate that the Public Housing customers pay change? Specifically, the 6 Cents/kWh?

QEC: The rate for public housing customers is the same as for residential customers but the GN subsidizes these customers significantly more so that they only pay 6 cents. The subsidy programs are determined strictly by the GN and are not subject to outside review and nor do they fall under URRC's authority to review. (RS comment: Is this expressed correctly?)

Councillor 2: Wondered why the residential rate was going up while the commercial rate was going down.

QEC: If we proceed to the uniform rate in Nunavut, Iqaluit residential rates will go up, and since the subsidy paid for non-Iqaluit consumption is 50% of the Iqaluit rate, non-Iqaluit customers' rates will rise. This reflects how the GN subsidy works currently but is at the GN's discretion.

Councillor 1 and the CAO: Is there a risk that the GN will remove or reduce the amount of money they are putting into their subsidy program?

QEC: There has been a long history of subsidizing our very high costs of energy by the GN. It is not likely to be removed or significantly altered by the GN as it would be very harmful to the people of Nunavut.

CAO: What hope is there for alternate renewable electricity power sources?

QEC: All renewable sources we have examined have significant issues, mainly being dependent on intermittent wind, days with no sunlight, and mostly financing that is prepared to pay for long return projects. QEC is happy to entertain IPPs (Independent Power Producers) but they can only pay them the avoided cost of the diesel that would otherwise be consumed.

Getting the funding for projects with such a long term of cost recovery is problematic.

Councillor 1: Expressed frustration as he felt that QEC should be able to access cheap financing for renewable energy projects as the municipalities can.

QEC: The GN debt cap prohibits QEC from doing this.

Councillor 1: Maybe the municipalities should use their funding for renewable energy projects. He feels that continuing to receive subsidies from the GN is not sustainable therefore they need to become more self-sufficient.

QEC: We would welcome the projects but must enter appropriate contracts to protect our current operations.

Councillor 3: Asked about the impact of the forthcoming carbon tax.

QEC: This matter is the subject of discussion between the GN and the Federal government. The first level, if implanted in Nunavut, will be assessed at \$10/tonne of CO_2. This will result in a need to recover an additional \$1.5 million from our customers, based on the fact that our operations contribute 150KT of CO_2. (RGL comment: This will rise to \$7.5 million as the tax rises to the mandated level of \$50/tonne of CO_2)

Mayor: Closed the meeting expressing support for the move to harmonized territorial rates.

December 7, 2017, Cambridge Bay, 10 attendees.

PARTICIPANT: Being both a business and a residential owner, are there any programs to encourage consumers to purchase more energy efficient appliances, such as LEDs, new windows, renovations, furnaces such as are being promoted and often subsidized in the south.

QEC: The Company has entered into joint discussions with the Nunavut Housing Corporation and the Climate Change Secretariat (GN) to explore opportunities and enhance energy awareness. However, we are just at the discussion stage. We are also awaiting Cabinet approval on a net metering program. In the future, QEC will be considering independent power production.

PARTICIPANT: As business owners, we simply have to invest in energy efficient measures now in order to remain competitive and viable. But, it would be of great assistance if an incentive program to assist in covering the costs was available. Discussions such as QEC has described never seem to come to fruition. There's been lots of discussion over the past 20 years since GNWT had a Renewable Resource office here. We need such a program now. We are doing our part because we have to in order to manage our costs and what we can't mitigate, then gets passed onto others in terms of higher rents. When is something going to be done by the GN or QEC.

PARTICIPANT: Are you able to extend power to our more remote cabins?

QEC: This is unlikely since the distribution system would result in voltage drops, impacting the quality of service to the community.

PARTICIPANT: Do you have plans for a new power plant in Cambridge Bay that will relocate the plant and result in less noise for the community?

QEC: Cambridge Bay is one of the remaining 11 communities which will require its power plant to be replaced. We are prioritizing based on the greatest need. When the Cambridge Bay plant is to be replaced, it will be relocated near the tank farm since the current plant site would not be sufficient to accommodate its replacement. Communities have also found that the new plants are quieter.

Jan 9, 2018, Pond Inlet, 17 attendees

PARTICIPANT:
Will harmonized rates in Nunavut affect everyone including elders and others collecting income through Family Services? If yes, will their subsidies increase? If not, I am not in agreement.

QEC: Good question, subsidies are determined by GN, not us or the URRC process, but we are interested in hearing this so that we can bring that forward to the government.
We can't guarantee anything but we can say that the government looks at this and is aware of the struggles of the people.

PARTICIPANT:
We working on this rate council before, I don't remember all the details but I would like more information on the process when it was NWT, when you want to harmonize the rate. How come it's taken so long for this process to take place?
I don't want to see harmonized rates because the communities are different in terms of how much light we have and the temperatures.

Lights are on more frequently in Pond and I don't think this has been given much thought. If they are going to be harmonized they need to take this into consideration.
What is the impact going to be on the elders and private home owners? If this is going to go ahead then we need to consider the different communities. My son works at the power plant in Iqaluit, I know how expensive it is and how new equipment is always needed.
What if we put in energy efficiency hardware, how would this affect us? Is it in the power plant or do we need solar plants and windmills.
There was a windmill here many years ago, maybe 60 years ago; maybe we should be looking at all these things for the future. See which works better and not just focus on generators. What can be made available to support the communities if we were to adopt these? It's expensive here, food, everything, we have to be considerate of all these things.
Please consider that communities are different in terms of darkness and coldness.

QEC: Community based rates were inherited from NWT, and they now have regional rates based on the different energy sources in those regions.

There are energy options we are working on with NHC and Energy Secretariat.

In terms of alternative energy we are working on a plan that should be done in a one year to one and half years and it will need to go through URRC, to use solar and wind but we will always have diesel plants because alternates are not always available.

What we think will be approved in the next week or so is net metering where homeowners can put up their own alternative energy options to reduce their dependency on diesel.

PARTICIPANT: Bills seem to be sporadic and we then get charged a late penalty. One time we even got cut off. Can the rate be decreased?

QEC: We can talk to you after the meeting regarding receiving your invoices. As for lowering prices, we need to recover our expenses and when costs go up; we have to increase our costs too.
Billing may seem like it comes more often but it's always sent out at the same time each month. (Nadia thought: maybe there is a problem with mail in Pond, takes longer?)

PARTICIPANT: QEC tried getting (Harmonized rates) about 4 years ago and it was opposed in communities. How come it was opposed that time, what was the issue?
What makes you think this is going to fly this time? What have you done different?

QEC: We were asked to look at options to rates, so we have. There were three examined: First, leave rate design as is with % increases across Nunavut, second, use community-based rates, and third, move toward Nunavut wide rates. We think this third option is the best way and are recommending it. I don't know what happened back in the day. But, we're doing these community consultations for this reason. The GN will decide in the end if this is the time to move forward with the harmonized rates.

PARTICIPANT: It says Pond Inlet in April 2019 it will increase 28 dollars and phase two increase by 22/month. I understand that, my question is how is that number derived from? When you harmonize it, what did you base it on? If it was to remain the same, not harmonized rates, what would the rates be?

QEC: The increase is based on an average customer using 500kWh per month and the change in the unit energy cost proposed.

PARTICIPANT: It's hard to pay everything in the winter, it's cold; all our expenses are huge in the winter and are bills all come in the same time. In the spring they decrease. Has this been taken into consideration for the high arctic, we don't average out, can the rates be flattened throughout the year?

QEC: We can look at flattening the invoices throughout the year so there is less hardship in the winter months.

PARTICIPANT: I'm glad you're here to hear from us elders because we are a vocal culture and I am looking forward to hearing what happens in the future, so please keep coming in person.

PARTICIPANT: In the summertime we get water flow from the rivers. Has QEC considered hydro as an option?

QEC: We've heard from other customers to get off diesel. We're doing internal reviews and looking at options and costs, including hydro, we're not locked into diesel, and we just need to make sure every community has reliable power. We haven't completed our review but we are looking at other energy sources to compliment diesel.

PARTICIPANT: I'm thankful you're all here, we have to work together, I'm not familiar with qallunaaq ways, sometimes as Inuit we seem angry these days, we're more into the qallunaaq ways, I want us all to work together and be more kind to each other. I'm thinking of people on social assistance, will they be paying more? If yes, that will be too bad because it's hard to make ends meet. We need to help each other. When it comes to paying bills, I always pay my bills; it would be so shameful to be kicked out of a home. I have a home and I always pay on time, I have no more to say.

QEC: Government is concerned with the impact on communities and citizens and so they will look at social assistance levels. QEC will discuss these concerns with the GN, but, the GN will make those decisions.

January 9, 2018 Igloolik, 19 attendees

PARTICIPANT: How do you define the season for the 700 kW and 1000 kW usage?

QEC: Winter is Oct-Mar.

PARTICIPANT: I'd like to ask about the power rates, diesel is used, are you looking in the future to use diesel all the time or alternatives down the road.

QEC: The short answer is we are looking at alternatives such as solar and wind but they are not available all the time so we need to have diesel as a back-up for reliable power. Alternatives can be expensive so we are looking at them but we don't want to increase costs. We have looked at nuclear as well, whether it's good or bad, we are looking at them all.

PARTICIPANT: As a mayor, we looked at utility costs we pay and our power plant is right next to the college, school, arena, centre of town and we've had power outage due to old lines. There is a concern that with the power plant so near to these public buildings, that a fire might do a lot of damage to the community. Lots of our lines need to be changed because the lines are too old. One of the lines snapped yesterday. Residents are affected by the rate increases and they are always affected and it's a concern because these residents often can't afford so many things and this is on top of their already very expensive costs. Also, elders can't afford increases and they don't understand the language on bills they receive so they don't know why their rates are increasing, I'm for harmonized rates and hopefully if the rates get approved, the company will provide better service.

QEC: We understand that rate increases have an impact on people and we will do what we can to keep rates affordable. QEC is very concerned about outages too. They are costly, and we don't want to worry about such issues either. We will do what we can to minimize such events.

PARTICIPANT: Will the rates be the same for homeowners and those in social housing or renters? Will homeowners have higher subsidies vs social housing?

QEC: Home owners pay more than public housing. We don't have control over the subsidies, that is a GN decision. However, we will be discussing the rates and subsidies with the GN in a way to provide info on what people are saying and the GN will make the final decision.

Chair: Describe difference between costs for renters, people with housing provided by employer, home owners, and public housing.

QEC: all residential customers pay the same except public housing; they are the only ones with the larger subsidies.

Cape Dorset, January 10, 2018, 21 attendees

PARTICIPANT: What is classified summer months and what is classified winter?

QEC: October to March winter; remainder of the year is considered summer.

PARTICIPANT: Will the rates increase after the power plant is completed?

QEC: The cost of the plants will be harmonized throughout NU. Once a new plant is put into operation, it is brought into the rate base at the next GRA process which sets new rates, meaning that a community (particularly those whose capital improvements are higher given certain technical and logistical reasons) do not experience a large spike in rates related to a new plant brought online in its community.

PARTICIPANT: Will the subsidies in the future remain the same?

QEC: The subsidy is solely a decision of the GN. However, we have had preliminary discussions with the government and are preparing additional information to meet the government's requests as they are reviewing how the subsidy is utilized. We have an opportunity to provide comments but the responsibility for the subsidy policy resides with the GN.

January 11, 2018, Iqaluit, 20 attendees

PARTICIPANT**:** You've mentioned a transition over 6 years to a Nunavut rate but this application only covers 2 years. What about the subsequent years following the first 2 years set out here?

QEC: The next Application would cover those years to get to the Nunavut rate of $.78 over the 6-year transition. The increase would be spread out evenly throughout those years.

PARTICIPANT: Does this Application incorporate the Impacts of carbon pricing?

QEC: No. Roughly we're talking about $1.5M at the rate of $10/tonne., and ultimately $7.5M at the $50/tonne rate. Since QEC emits about 150 Kilo tonnes per year, over 15,000 customers, will have to pay approximately $500/customer when implemented completely.

PARTICIPANT: Have the impacts considered the proposed increase on the private sector vs private homeowners? In particular, Iqaluit has the greatest proportion of private enterprise and private home ownership of Nunavut (approximately 60% and 70% respectively). Need to weigh the benefits versus burden experienced. Does the proposal reduce the GN costs at the expense of private home owners?

QEC: QEC does not undertake that type of analysis. The subsidy is administered by the government and QEC will be providing information to them. The GN will determine the appropriate subsidy.

PARTICIPANT: Has QEC considered addressing rate tactics (as in the south) to address demand at peak and non-peak hours. (Asked as an owner of future manufacturing business)

QEC: In the south, times of use rates are employed to flatten out demand and manage capacity more wisely. “Economic dispatch” is a concept used in the south and is used to defer capital expenditures.

In Nunavut, there is a different model. We do not have the use of a grid. Focus on base is on providing sufficient generating capacity to meet peak demand and efficiency focus is on dispatching the most efficient generation equipment.

PARTICIPANT**:** Who buys your fuel?

QEC: PPD buys the fuel on the market and sells it to QEC

PARTICIPANT: In the past, it was applauded when fuel was purchased at a significantly low price but additional supply was purchased at exorbitant rates and nothing was reported. What’s the impact on the customer?

QEC: In January of every year, the GN publishes the fuel rate. Our rate is listed there. It is not subsidized. QEC pays the full rate. It is different from other rates that are subsidized. It is a commercial relationship between PPD and QEC.

PARTICIPANT: Concerned about homeowners facing increased rates and fuel rate hikes. Does QEC take into consideration the household size when it deals with the 700 kWh threshold?

QEC: QEC does not differentiate between households of 1 versus households of 4 or 5. That’s a pretty standard approach across many jurisdictions.

PARTICIPANT: Does the company have any idea of the cost increase that will result from capital projects currently under way?

QEC: Costs of projects in any community are spread out across the territory. Yet we realize that the % increase between today’s rate for Iqaluit and the NU rate of $.78 is large. Can’t get around that percentage increase. As new plant is brought into the rates, the rates will increase further.

PARTICIPANT: Alternative energy options have been proposed for residential users with excess being fed back into the grid. Will that be expanded to non-residential customers?

QEC: What you’re talking about is QEC’s Net Metering Program. Residential users can generate up to 10 kwh supply on their property. Excess can be fed to QEC and credited back later. Any credit remaining will be zeroed out at each March 31.

Broader rollout is being developed, but legislation and regulations need be changed and Terms of Service need to be revised.

PARTICIPANT: The Independent power producer program is to come in time. Options from solar to nuclear are being examined. However, these systems are not necessarily reliable as they are intermittent, so QEC still needs to maintain reliable generation capacity.

PARTICIPANT: What are the projections on net metering? How popular do you anticipate it to be?

QEC: We believe the desire is there but cost may quickly become an issue. NWT had limited uptake. We also want to limit the uptake so that we can access the technical impact on the existing system.

PARTICIPANT: Has QEC considered taking a lead on a bulk purchase of solar panels to reduce cost to the ultimate household user?

QEC: We are looking into that but have not progressed at this stage. The concept of cost of the panels is interesting and the cost is coming down. In the end, it may be transportation and installation may become the more significant issue. There is a lot of cost to get to what is termed "grid parity".

January 12, 2018, Qikiqtarjuaq, no attendance

January 13, 2018, Iqaluit, 10 attendees, no questions were asked.