NORTHWEST TERRITORIES POWER CORPORATION
GENERAL RATE APPLICATION

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INTRODUCTION

1.0 INTRODUCTION

1.1 APPLICATION OVERVIEW

The Northwest Territories Power Corporation ("NTPC" or the "Corporation") hereby files a General Rate Application ("GRA" or "Application") with the Northwest Territories Public Utilities Board ("PUB") for the Test Years 2016/17, 2017/18 and 2018/19. The Application is filed in accordance with Decision 13-2014 that established the Standardized System of Accounts ("SSA") and Minimum Filing Requirements ("MFR"). The GRA describes all aspects of NTPC's costs for the Test Years. Included in the Application are actual costs for fiscal years 2013/14 and 2014/15, forecast costs for 2015/16, and forecast costs for the Test Years 2016/17, 2017/18 and 2018/19.

Consistent with its last GRA, the Corporation is seeking to transition customers to the required higher level of rates over a three year period. Specifically, the proposed increases are approximately 4.8% for 2016/17, 4% for 2017/18 and 4% in 2018/19, for an aggregate increase of 12.8%. As a result of this approach, the Corporation will forgo earning an industry appropriate return on equity until at least 2018/19. The Corporation will forgo collection on the 2016/17, 2017/18 and 2018/19 shortfall, if any, from customers. Any changes to the 2016/17 and 2017/18 Revenue Requirement would

only impact the Corporation's uncollected revenue shortfall and not the Corporation's proposed rate increase of 4.8% and 4%. Consistent with the Government of the Northwest Territories (GNWT's) rate policy guidelines from February 2015, the Corporation is not seeking to adjust customer charges or demand charges. The GRA total Revenue Requirement and revenue forecast reflect shortfalls of $3.6 million in 2016/17, $2.7 million in 2017/18 and close to full recovery by 2018/19. The shortfalls compared to existing rates and proposed rates are set out in Table 1.1.

Table 1.1

Revenue Requirement versus Revenues at Existing Rates ($000s)

	Test Year		
	2016/17 Forecast	**2017/18 Forecast**	**2018/19 Forecast**
Total Revenue Requirement	110,072	113,212	114,824
Revenue at Existing Rates	100,201	100,389	100,396
Other Revenue	1,714	1,714	1,714
Total Revenue	101,914	102,103	102,109
Shortfall at Existing Rates	8,158	11,109	12,715
Revenue at 4.8/4/4% Annual Base Rate Increase	106,398	110,523	114,614
Shortfall at 4.8/4/4% Annual Base Rate Increase	3,674	2,689	210

The Corporation filed a request for interim rates effective August 1, 2016 on June 30, 2016. The Corporation is requesting interim rates to increase energy charges for all customer classes in all communities by 4.8%.

The Corporation has received substantial financial support from its Shareholder the GNWT since the 2012/14 GRA. Reflected in this GRA are increases to Customer Contributions from the GNWT to finance alternative energy projects and financial relief to fund the cost of fuel associated with the 2016/17 Snare Falls Overhaul. In addition,

the GNWT provided financial relief for the increased cost for fuel, overhauls and maintenance resulting from the extreme low water on the Snare system. In May 2016 as a cost saving measure the GNWT also replaced the Corporation's Board of Directors with a Board of GNWT Deputy Ministers. This action reduced the Corporations Revenue Requirement. These capital and operating contributions made by the GNWT, have reduced Revenue Requirement and are reflected in this GRA to the benefit of the Customers by lowering ongoing operational costs reducing Rate Base and reducing deferred account balances. Table 1.2 gives an overview of the proposed energy rates for 2016/17, 2017/18 and 2018/19.

Table 1.2
Proposed Energy Rates

Proposed Energy Rates

Plant Number	Community Name	2016/17 Proposed Energy Rates					2017/18 Proposed Energy Rates					2018/19 Proposed Energy Rates				
		Residential (c/kWh)	General Service (c/kWh)	Wholesale (c/kWh)	Industrial (c/kWh)	Lighting (c/kWh)	Residential (c/kWh)	General Service (c/kWh)	Wholesale (c/kWh)	Industrial (c/kWh)	Lighting (c/kWh)	Residential (c/kWh)	General Service (c/kWh)	Revenue from Wholesale (c/kWh)	Revenue from Industrial (c/kWh)	Revenue from Lighting (c/kWh)
Non-Government Sales																
Snare Zone		**32.59**	**40.13**	**20.13**	**15.71**		**33.90**	**41.73**	**20.94**	**16.34**		**35.25**	**43.40**	**21.77**	**16.99**	
Taltson Zone		**22.01**	**17.32**	**11.35**			**22.89**	**18.02**	**11.80**			**23.80**	**18.74**	**12.28**		
Taltson Interruptible				**5.68**					**5.91**					**6.14**		
Thermal Zone		**63.75**	**54.08**				**66.30**	**56.24**				**68.95**	**58.49**			
Norman Wells in Transition		49.82	45.27				51.81	47.08				53.89	48.97			
Government Sales																
125	Behchoko	33.60	41.36			96.46	34.94	43.02			100.32	36.34	44.74			104.33
126	Dettah	37.48	46.45			82.47	38.98	48.31			85.77	40.53	50.24			89.20
123	Wha Ti	113.76	105.60			186.82	118.31	109.82			194.29	123.04	114.21			202.06
124	Gameti	174.60	200.67			224.43	181.58	208.70			233.41	188.84	217.05			242.74
127	Lutsel K'e	105.64	98.24			168.00	109.86	102.17			174.73	114.26	106.26			181.71
128	Fort Smith	22.01	17.32			32.54	22.89	18.02			33.84	23.80	18.74			35.20
130	Fort Resolution	27.91	24.25			45.82	29.02	25.22			47.65	30.19	26.23			49.56
131	Fort Simpson	98.78	86.54			110.82	102.74	90.01			115.25	106.85	93.61			119.86
132	Fort Liard	105.00	94.66			162.02	109.20	98.44			168.50	113.57	102.38			175.24
133	Wrigley	185.53	198.40			258.36	192.95	206.33			268.70	200.67	214.59			279.45
134	Nahanni Butte	223.83	288.73			343.52	232.79	300.28			357.26	242.10	312.30			371.56
135	Jean Marie River	200.02	269.90			360.54	208.02	280.70			374.97	216.34	291.93			389.96
136	Inuvik	81.18	72.21			95.22	84.43	75.10			99.03	87.80	78.10			102.99
137	Norman Wells	60.14	54.64			80.33	62.55	56.83			83.54	65.05	59.10			86.88
138	Tuktoyaktuk	95.23	84.57			129.22	99.04	87.96			134.39	103.00	91.47			139.76
139	Fort McPherson	109.75	100.40			122.61	114.14	104.41			127.51	118.70	108.59			132.61
140	Aklavik	87.21	83.34			117.47	90.70	86.67			122.17	94.33	90.14			127.06
141	Deline	111.92	105.60			95.98	116.39	109.82			99.81	121.05	114.21			103.81
142	Fort Good Hope	97.40	85.31			113.57	101.30	88.72			118.11	105.35	92.27			122.84
143	Paulatuk	165.34	156.24			183.10	171.96	162.49			190.42	178.83	168.98			198.04
144	Sachs Harbour	204.62	191.79			219.38	212.81	199.47			228.15	221.32	207.44			237.28
145	Tsiigehtchic	151.61	134.30			192.18	157.68	139.67			199.87	163.99	145.26			207.86
146	Colville Lake	309.74	269.38			770.87	322.13	280.15			801.70	335.01	291.36			833.77
147	Ulukhaktok	95.17	86.15			125.71	98.98	89.59			130.74	102.93	93.18			135.97
148	Tulita	120.40	116.30			138.82	125.22	120.95			144.37	130.23	125.79			150.15

1.2 CORPORATE BACKGROUND

NTPC is the main generator and transmitter of power in the Northwest Territories (NWT). NTPC provides power on a wholesale basis to Northland Utilities (YK) Ltd. in Yellowknife and to Northland Utilities (NWT) Ltd. in Hay River and area. NTPC provides industrial service to the Environmental Protection Division for Giant Mine and provides generation and distribution services to retail residents in most of the remainder of the NWT. The Corporation exists in a unique operating environment. Extremely low customer densities, a harsh climate and the consequential logistics challenges, as well as the lack of an integrated transmission system, set the Corporation apart from most utilities. This environment has a profound impact on the Corporation's operations throughout its service area.

NTPC is established under the *Northwest Territories Power Corporation Act*, and is wholly owned by the GNWT through the holding company NT Hydro. NT Hydro is a public agency, established in 2007 under the *Northwest Territories Hydro Corporation Act*. NT Hydro has two wholly-owned subsidiaries, NTPC and the NWT Energy Corporation Ltd. ("NWTEC"). NWTEC under authority of the *NWT Energy Corporation Ltd. Loan Guarantee Act*, financed the Dogrib Power Corporation in 1996 for the construction of a 4.3 MW hydro facility. NWTEC is also responsible for the operation, management and shared ownership (50%) of one residual heat project in Fort McPherson, which was established in 1996. The only services provided by the

Corporation and received by affiliates, are for the residual heat project in Fort McPherson and further discussed in Chapter 12.

The Corporation's systems serve a population of approximately 42,000 located in an area of 1.3 million square kilometres. The total electrical peak load is approximately 60 MW, with isolated power systems having generating capacities ranging from 63 MW for the Snare zone and 266 kW at Jean Marie River (total installed capacity of approximately 144 MW). NTPC maintains 3 hydroelectric systems, 4 solar arrays, 1 natural gas plant and 28 diesel plants. As the majority of the systems are isolated and unconnected, each must be planned for and operated independently. Two of these systems are dominated by hydro (the Snare-Yellowknife system serving Yellowknife, Behchoko and Dettah, and the Taltson system serving Fort Smith, Fort Resolution and Hay River) while the rest are non-interconnected communities served by thermal generation (diesel or natural gas) with compliments of renewable energy such as solar. The Corporation also maintains approximately 565 km of transmission lines, 375 km of distribution lines and 9,800 poles. For the 2016/17 Test Year approximately 75% of total generation is from Hydro and 25% is from thermal generation sources. A small amount, 0.1% is from solar generation.

1.3 STRATEGIC DIRECTION OF THE UTILITY

NTPC's mission is to generate, transmit and distribute electricity in a safe, reliable, efficient and environmentally sound manner while striving to reduce reliance on fossil

fuels. NTPC exists to provide value to its Stakeholders through the efforts of a highly dedicated, skilled and productive workforce.

NTPC's strategic goals are:

1. Realize zero injuries through superior safety performance and practices;
2. Accomplish environmental sustainability through increased use of renewable energy;
3. Achieve high levels of reliability while maintaining affordably priced electricity;
4. Meet or exceed all customer commitments;
5. Develop and retain a highly skilled workforce that reflects the demographics of the NWT;
6. Support economic development and growth throughout the NWT;
7. Be efficient and effective in our daily operations through continuous improvement;
8. Support communities and encourage employee involvement;
9. Educate customers and youth about conservation; and
10. Meet the future energy needs of NWT residents through proactive planning and consultation.

The strategy NTPC has employed over the past three years is one of supporting economic development while focusing on core business and three fundamental concepts:

1. Reliability

2. Cost Effectiveness
3. Meeting Commitments.

By focusing on these three fundamental needs, NTPC brings value to its stakeholders.

Reliability

While NTPC works within one of the most challenging environments in Canada, NTPC must endeavor to meet the needs and expectations of its customers with respect to reliability.

Initiatives supporting reliability include:

- The development of Key Performance Indices (KPIs) measuring reliability of service in the communities NTPC serves. These are industry standard measures that will allow comparison of NTPC's service to that of other utilities. The NTPC System Average Interruption Duration Index (SAIDI) KPI (indicates overall reliability) went from 4.8 in 2015 to 2.4 in 2016 showing an overall improvement in the measure as well as the 5 year average. Please refer to section 14.6 for the reliability statistics;
- The development and implementation of a computerized maintenance management system, which included the development and formalization of standardized work procedures for both hydro and thermal assets along with a risk/condition based assessments of all NTPC assets, and the development of a long term power system plan to identify a long term capital replacement plan for the Corporation;

- A review of the maintenance planning process for hydro shutdowns to ensure hydro capacity is maximized and water license requirements are met;
- Exciter upgrade at Snare Forks Hydro;
- Improving the stability of the Snare/Yellowknife System through coordination study and upgrade of governors on hydro units;
- Designing, constructing and operating the diesel/solar/battery hybrid plant in Colville Lake;
- Continuing to execute the vegetation management program for transmission and distribution improving reliability; and
- Continuing to work on the 14 YK Reliability Initiatives. Only two initiatives remain uncompleted (Governor Upgrades of all Snare Plants and Jackfish Substation Cover Up), both of which will be completed by 2018 at a rate of one plant per year, with the cover up to be completed this year once back on full hydro.

These initiatives allow NTPC to better plan and manage maintenance activities as well as capital replacements, and will improve cost effectiveness as well as reliability in the long run.

Cost Effectiveness (the price of electricity)

NTPC needs to be efficient and effective with its resources by looking for cost-effective solutions to its challenges and to hold controllable costs at or below inflation.

Initiatives over the past three years aimed at reducing costs or making the most efficient use of resources include:

- Working with the PUB and other stakeholders to develop a standardized minimum filing requirements to maximize the amount of information provided for review of GRA's while reducing the time and costs associated with these Applications;
- A move towards In-house overhauls of critical equipment & prime movers (thermal);
- Work with GNWT and other parties such as the Northern Stores, Co-ops, Hamlets, and vendors to identify additional opportunities for co-operative savings through shared charters & actuarial services and vendor partnerships and alliances;
- Development of the capital planning process is completed and now mature enough that adoption is largely complete with only minor improvements occurring. Benefits are being seen by Corporation with more projects being completed with less scope creep;
- Light Emitting Diode (LED) street lights were installed in all communities that NTPC serves, except Fort Smith, improving lighting quality and reducing the consumption for municipal governments;
- Station service reductions of thermal plants lowered emissions and costs due to plant lighting conversions to LED and installation of Variable Frequency Drive (VFD) drives;

- Pursuing the development of Taltson Hydro in partnership with SaskPower, an initiative with potential to advance given the environmental parameters at this time are more conducive than they have been in the past;
- Working in conjunction with the GNWT to investigate and develop renewables or alternative generation options to diesel plants such as Liquefied Natural Gas (LNG) based generation, net metering, wind monitoring in Inuvik at two locations along with a single location at Snare Hydro, solar projects in Fort Liard and Wrigley, and LED streetlight conversions in all communities;
- Working with the GNWT, to create projects which have a low/no Rate Base impact and reduce costs for customers;
- Negotiation of fuel supply contracts benefitting customers through fuel costs savings in Aklavik and in Norman Wells, saving money on the price of power generation;
- The CMMS - Standalone Phase was completed and fully integrated into the Corporations operations. Positive reports from the field have been received as well as indications of early efficiency and productivity benefits including improved coordination and sharing of regional staff during shutdowns and maintenance. Development of plans for the financial integration component of CMMS, which will improve asset maintenance and management processes starting in 2017/18;
- A new zero based budgeting process is now fully implemented and has led to improved accountability down to the manager level with better future coordination with maintenance plans;

- Refocused the function of Internal Audit to include a focus on continuous improvement (CI). Continuous improvement will drive NTPC to further review and refine processes to improve efficiencies within the process. There were four CI projects completed in the Finance Division that improved four different processes, along with the establishment of the Project Management Center of Excellence established as a CI initiative in 2015/16 in the Asset Management and Engineering Division;
- Identifying and implementing improvements to the Land Use Process;
- Weather station deployed at Taltson airstrip to aid in condition awareness for pilots traveling to site;
- Reviewing and updating all Finance policies and financial reporting framework for the dual reporting framework of Public Sector Accounting Standards (PSAS) and Rate Regulated Accounting (RRA), and communicating those changes in reporting to NTPC's Board and its employees;
- Improving the use of Information Technology through an audit of Hay River and Yellowknife local area networks, upgrading Snare Hydro internet communications, optimizing Microsoft licensing and leveraging technology to lower cost and improve productivity through such initiatives as: Skype for Business, Voice Over Internet Protocol (VOIP) and desktop virtualization;
- Installing EMD in Inuvik as part of Long Term Capacity Planning; and
- Converting Wartsila gas engines to diesel as part of Inuvik Long Term Capacity.

Meeting Commitments Made

It is imperative that NTPC and its employees meet commitments made to customers. This will largely be achieved by shifting the corporate culture to one of having a business and safety focus, as well as increasing respect for both customers and stakeholders, such that every effort is made to fulfill commitments made to these two groups.

The message of the importance of customer satisfaction has been communicated and will continue to be reinforced at all levels of the organization. To succeed a corporate strategy must recognize that the foundation of every organization is its people. Furthermore, employee excellence in every aspect of a corporate strategy is necessary to deliver full value to an organization. Employee excellence is the foundation of NTPC's strategy.

Initiatives undertaken to improve commitments to customers, employees and stakeholders include:

- New safety initiatives include minimum safety meeting attendance for all employees, two new Health and Safety metrics measuring culture, evaluation and updating of internal Work Protection Code to address employee concerns that were raised in employee survey, a refocus on safety culture, the development and roll out of the Lone Worker System, updated Health & Safety Management System Training, improved functionality of Joint Occupational Health and Safety Committees; improved incident investigation program, COR

Safety Certification & Successful Audit and the issuance of arc flash protection to all workers exposed to arc hazards;

- Received CEA Bronze Award for exceptional safety performance against CEA peers;
- No debilitating injuries to employees or contractors;
- Completing a number of employee surveys on safety, corporate culture and employee satisfaction. Management is working with employees from across the Corporation to better understand and address employee concerns;
- Launched a new Employee Recognition Program (KUDOS);
- Developing and implementing standardized processes for training, including a management training program in partnership with Aurora College. Launched online training library “ntpc.bizlibrary” incorporating e-learning technology into our new blended learning approach, and developed a comprehensive plant operators/superintendent training and a program for thermal operations;
- Continuing to strengthen our employee workforce through the apprenticeship program;
- Creating employee development plans to improve employee performance and engagement;
- A new Careers website was developed highlighting not only the opportunities to work for NTPC but also the benefits of living in the North;
- Implementation of a Communications strategy currently being executed including the use of technology to better meet the needs of customers and employees

such as an improved internal communications page, social media, improved outage information for customers and other customer information;

- Developing and strengthening stakeholder relations including relations with the GNWT. Extensive work to build relationships with communities between the Corporation, Senior Management, and local staff;
- Completion of KPIs for New Customer Connection Times;
- Development of customer service 5-Year Plan including customer educations pieces completed and distributed in bill stuffers highlighting NTPC's renewable projects and rate information to be released this spring;
- Intelligent Metering Hub (IMH) Pilot project was completed in Jean Marie with support of Federal Government;
- Working with the PUB for Interruptible electric heat program made available to customers in the South Slave;
- Developing and implementation of a collections strategy;
- Conclusion of the net metering pilot project and reporting to PUB;
- Development of micro generation application, internal review, and approvals process;
- Secure Norman Wells long term capacity planning;
- Development of energy efficiency initiatives for residential customers and a large customer energy efficiency assessment; and
- Develop Support for Community Initiatives that support the environment.

Moving Forward

There are four common themes for the organization in terms of its future focus:

- Communications
- Training
- Safety
- Leadership

NTPC considered the need to improve reliability and enhance efficiency as well as to decrease dependency on fossil fuels given the current operating environment. In conjunction with the fundamental concepts the Corporation has developed 26 initiatives representing the strategic direction in the coming Test Years:

Employee Excellence Initiatives

1. Developing our employees;
2. Improved communication with our employees;
3. Continued strategic focus on safety culture enhancement;
4. Continued strategic focus on contractor safety;
5. Human Resources comprehensive plan development;
6. Successful collective bargaining negotiations leading to an amicable resolution; and
7. Organizational Culture Inventory (OCI); continued measurement and improvement towards a “constructive” culture.

Operational Excellence Initiatives

8. Implementation of divisional/departmental level strategic planning across the organization;
9. CMMS: Cultural integration and adoption;
10. Asset management framework development and roll out;
11. Investigate 7-10 MWs of Wind Energy within proximity of Snare;
12. Investigate 3-5 MWs of Wind Energy at storm hill in Inuvik;
13. LNG plant design/approvals - Fort Simpson;
14. Variable speed engine pilot – Aklavik;
15. Bluefish Redevelopment planning;
16. GNWT funded solar projects; and
17. Transmission interconnection paper that comes with phased options.

Customer Service Excellence Initiatives

18. Five year plan for Customer Service and virtual call centre development;
19. South Slave heat sales program roll out;
20. Continued Stakeholder engagement; and
21. Intelligent Metering Hub (IMH) in Jean Marie and potential further roll outs;

Financial Excellence Initiatives

22. PSAS cultural integration;
23. 2016/19 GRA successful completion;
24. NTPC risk registry development;
25. CMMS: Financial integration; and

26. Power system plan with development of a 20 year capital plan and a detailed five year capital plan.

1.4 REGULATORY HISTORY

NTPC's last Phase I General Rate Application was filed in March 2012 for the 2012/13 and 2013/14 Test Years. Rates that implemented the full 2013/14 Revenue Requirement were phased in, with the final rates being implemented effective April 1, 2015.[1] In the intervening years, NTPC has faced challenges associated with, among others, cost pressures from normal ongoing inflation of typically about 1-2% per year.[2] The Corporation's actual net earnings were $5.0 million in 2014 (6.3% return on equity) and $0.6 million in 2015 (0.7% return on equity).

NTPC and its customers are dealing with challenging times with respect to the costs and/or availability of resources to operate, maintain and invest in the company, notably:

Aging Infrastructure: Many of NTPC's generating facilities were constructed in the 1970's or 1980's and in some cases, such as the Corporation's hydro plants, even earlier. NTPC has worked to use existing assets or upgrade existing plants to meet current service requirements where possible. However, the inevitable aging of the basic infrastructure will continue to require NTPC's investment in a capital replacement program to maintain reliable service for customers.

[1] Rates for April 1, 2015 were approved in Board Decision 8-2015.

[2] The CPI for Yellowknife increased by 1.3% in 2014/15 and 1.4% in 2015/16.

Increased Regulation: Responding to changes in regulation requires both human and financial resources, and the 2016/19 GRA incorporates the resources needed to meet these obligations under the new regulatory regimes.

Inflation Compared to Lack of Sales Growth: NTPC's loads have in many cases stagnated or even declined since 2013/14. Company wide sales for 2016/17 are forecast to be 14 GWh lower than forecast in the 2012/14 GRA, a decrease of 1.5% per year. Upward pressure on rates from general inflation is compounded by decreased sales, particularly in the hydro zones where there are little or no fuel savings associated with decreased sales.

1.5 FORECAST ASSUMPTIONS

NTPC's Application is based on the Corporation's most recent load forecast, operations and maintenance budget and capital budgets. High level assumptions used in preparing the forecasts include:

- Salary and wages reflect step increases as per the existing collective agreement.
- Inflation for operation and maintenance expenses of 2% annually for 2017/18 and 2018/19.
- Little to no economic growth, consistent with the GNWT's January 2016 fiscal framework with the result that sales are forecast to be relatively flat at a Corporate-wide level throughout the Test Years.

- Long-term debt interest remains constant as all debentures have fixed rate debt. A new debenture is forecast in 2016/17 and the interest rate reflects the 30 year Canadian benchmark bond yield.

1.6 CHANGES IN ACCOUNTING STANDARDS, POLICIES AND PRACTICE

NTPC had historically been able to maintain its operations and meet its liabilities through the rate regulation process without receiving any significant financial assistance from the GNWT and has been classified as a Government Business Enterprise (GBE) which required reporting as a publically accountable enterprise. At the time of the last GRA, publically accountable enterprises were required to transition from Canadian GAAP to International Financial Reporting Standards for fiscal years beginning on or after January 1, 2015. Therefore, NTPC was intending to adopt IFRS for its fiscal year ending March 31, 2016.

In order to mitigate rate increases to customers in the 2012/14 GRA, the GNWT provided large subsidizations to customers through rates by providing direct contributions to NTPC to apply against balances in the fuel stabilization funds, graduate the impact of rate increases to customers and offset the cost of extreme low water in Yellowknife.

As a result of this government driven policy, and the expectation that the ongoing operations of NTPC would depend on continued financial support from GNWT, NTPC was determined to be economically dependent on the GNWT to maintain its operations and meet its liabilities. This economic dependence resulted in an accounting

classification change from a GBE to an Other Government Organization (OGO), beginning in 2014/15.

Given NTPC's regulatory and public reporting responsibilities, NTPC has adopted a dual reporting framework, which allows for financial reporting under both PSAS and Rate Regulated Accounting (RRA) required for regulatory submissions. NTPC's policies have been updated to reflect appropriate reporting for RRA transactions and PSAS transactions.

Differences between NTPC's audited PSAS financial statements and NTPC's RRA financial statements are identified below:

i) Reclassification adjustments

Functionalization of expenses

RRA presented expenses by object. PSAS requires that expenses be classified by function, with note disclosure providing expenses by object.

Related party balances

Under RRA, NTPC presented the net receivable from related parties in the consolidated balance sheet. Under PSAS, no similar presentation exists. PSAS requires the net receivable from related parties be reclassified to revenues receivable.

Current portion of assets and liabilities and sinking fund investments

The current portion of assets and liabilities are not presented under PSAS. As a result, the current portion of assets and liabilities under RRA were reclassified to the appropriate asset or liability balance.

Loan receivable and capital lease obligation

Under RRA, NTPC's capital lease obligation was offset against its loan receivable from DPC for financial statement presentation and disclosure. PSAS does not allow for this netting; therefore under PSAS the loan receivable is reclassified from the capital lease obligation to a receivable balance in the statement of financial position. In addition, the associated interest income from the loan receivable has been reclassified from an offset to interest expense to interest income.

ii) Rate regulated accounting

Under RRA, NTPC uses regulatory deferral accounts as a way to smooth the rate impact of these events. Actual costs for these events are added to the deferred accounts and a PUB prescribed annual expense is included in net income to offset the cost of these events over time. Under PSAS the annual cost of these events are recorded in net income and there are no regulatory deferral accounts.

Capitalized fuel

Under RRA, NTPC capitalized fuel associated with a capital project as a result of Decision 27-2008. Under PSAS, the capitalization of this fuel is not permitted in tangible capital assets and these costs would be recognized as an expense when incurred.

Inventories

Under RRA, IDC was added to the cost of major spare parts inventory while it was being held for installation. Under PSAS, IDC on inventory is not permitted. As a result IDC earned on major spare parts has been added to the balance of regulatory deferral accounts.

iii) Tangible capital assets adjustments

Under RRA, enterprise software was presented at March 31, 2014 as an intangible asset. Under PSAS, such assets are included in tangible capital assets.

Under RRA, tangible capital assets replaced under insurance were recorded at full value with the insurance proceeds capitalized as an offset and amortized as a reduction to amortization expense on the same basis as the amortization of the related tangible capital assets. Under PSAS, NTPC is required to recognize insurance proceeds as proceeds on disposal when there is reasonable assurance NTPC will receive the proceeds or they have been received.

Under RRA, the straight-line average group useful life basis of amortization supported recognizing the gains and losses on disposal or abandonment of tangible capital assets in accumulated depreciation. PSAS does not allow for the application of this amortization principle and requires the net gain or losses on disposal or abandonment of tangible capital assets to be recognized as an expense when incurred.

Under RRA, NTPC reported critical spare parts under tangible capital assets for those inventory items where substitutes were not readily available and/or fabricated, the absence of the item would have caused a significant loss of asset service availability

and there was an expectation the asset had benefit extending beyond one year. PSAS requires that tangible capital assets be currently in service; therefore under PSAS critical spare parts are reclassified from tangible capital assets to inventory.

Under RRA, feasibility studies were considered tangible capital assets as they provided long-term benefits to NTPC. PSAS requires that tangible capital assets to have physical substance and therefore feasibility studies are expensed when incurred.

Under RRA, NTPC deferred contributions received from customers or the government for the acquisition or construction of tangible capital assets to connect them to the network. These deferred contributions were set up as regulatory liabilities and amortized and recognized against amortization expense at the same rate as the related capital assets. Under PSAS, deferred contributions received from customers or the government are recognized as revenues in the period in which the related assets are acquired or constructed.

Asset retirement obligations and environmental liabilities

Under RRA, AROs were recognized on a fair value basis by discounting the estimated future cash flows using NTPC's credit-adjusted risk-free rate and were recognized as an adjustment to a regulatory reserve. Under PSAS, AROs are recognized on a best estimate basis by discounting the estimated future cash flows using NTPC's cost of borrowing and an adjustment to tangible capital assets. As a result, under PSAS AROs increased as did the balance of tangible capital assets. In addition, there were increases

in amortization expense and the addition of accretion on AROs expense under PSAS, which does not exist under RRA.

iv) Other

Debenture debt

Under RRA, the costs related to an extinguishment of a debt transaction were deferred and amortized over the term of the new debt. Under PSAS, these costs would be recognized as an expense when incurred.

Employee future benefits

Under RRA, NTPC did not recognize an obligation for non-vesting accumulating sick leave benefits. Under PSAS, these accumulating benefits are recognized.

Dividends

Under RRA, dividends were a drawdown of retained earnings. PSAS requires these payments to be reflected as expenses in net income.

1.7 REGULATORY DEFERRAL ACCOUNTS AND DEFERRED EXPENSES

The Corporation utilizes five deferral accounts and one account for deferred expenses. Deferral accounts are established by the PUB when expenditures have benefits that extend beyond a single year and the expenditure is not covered in the Corporation's current Revenue Requirement. The purpose of the accounts is to levelize the charges to customers (via Revenue Requirement) at a standard normalized amount each year.

Table 1.3 below shows the Corporation's deferral accounts and deferred expenses and when they were approved by the PUB for deferred cost treatment.

Table 1.3
PUB Approved Deferral Accounts and Deferred Expenses Account

Account	Approval
Regulatory Deferral Account	2001/03 GRA
Overhaul Deferral Account	2001/03 GRA
Water License Deferral Account	2006/08 GRA
Reserve For Injuries and Damages Account	1992/93 GRA
Employee Future Benefits Account	2012/2014 GRA
Deferred Expenses	SSA/MFR Approval

Regulatory Deferral Account

Deferral account to capture and review all regulatory hearing-related costs and costs incurred by the Corporation for studies or programs directed by the PUB.

Overhaul Deferral Account

Deferral account to capture and review engine overhauls for thermal and hydro generating plants.

Water License Deferral Account

Deferral account to capture and review the costs of water licensing activities including regulatory costs, dam safety studies, annual dam inspections, environmental

monitoring, environmental studies and costs directed by the regulator or as a requirement from a dam safety study.

Reserve for Injuries and Damages Deferral Account

Deferral account to capture and review costs for uninsured or uninsurable losses and the deductible portion of insured claims.

Employees Future Benefits Deferral Account

Deferral account to capture and review costs associated with the liability for employee future benefits.

Deferred Expenses

Cost for studies and programs that results in an intangible asset that has a benefit for more than one year. Appropriate deferral expenses have to meet the following tests:

1. There is a benefit to the Corporation and its Customers of more than one year; and
2. The expenditure is not covered in the Corporation's current Revenue Requirement.

For details on the costs associated with the deferral accounts and the deferred expenses please refer to schedules 11.4, 11.5 and section 11.4.

1.8 APPROVALS REQUESTED IN THE APPLICATION

Pursuant to the provisions of the *Northwest Territories Public Utilities Act*, NTPC hereby seeks an Order or Orders of the Board:

1. **Approving the Test Year Revenue Requirements** of $110.072 million in 2016/17, $113.212 million in 2017/18 and $114.824 million in 2018/19, as set out in chapter 3 of the Application, including approval as required of the following costs and revenues:

    a) ***Operating and Maintenance Expenses*** of $42.185 million in 2016/17, $43.372 million in 2017/18 and $44.023 million in 2018/19 for non-fuel expenses.

    b) ***Fuel Expenses*** of $23.400 million in 2016/17, $23.912 million in 2017/18 and $24.360 million in 2018/19 for fuel and purchased power expenses. Variances from fuel prices approved as part of the GRA will be charged to or credited to NTPC's territory-wide Stabilization Fund.

    c) ***Amortization Expenses*** (net of customer contributions) of $24.273 million in 2016/17, $25.412 million in 2017/18 and $26.102 million in 2018/19. Amortization expense is comprised of fixed asset amortization, fixed asset true-up and amortization of deferred charges. NTPC is seeking the following approvals:

        i. To adopt new asset amortization rates as determined in NTPC's 2016 Depreciation Study performed by Gannett Fleming for all asset classes.

ii. To amortize all variances arising as a result of the new depreciation rates over the average remaining life of the respective asset class, with a minimum period of 5 years.

iii. To turn net salvage rates back on for future removal and site restoration in a phased approach.

iv. To increase the annual appropriation for regulatory hearing costs from the $0.257 million per year level approved in the 2012/14 GRA, to $0.512 million per year.

v. To increase the annual amortization of the normalized overhaul deferral account from an annual level of $2.936 million per year approved in the 2012/14 GRA to $3.935 million per year.

vi. To increase the annual amortization of the water licencing deferral account from an annual level of $0.825 million per year approved in the 2012/14 GRA to $1.611 million per year.

vii. To decrease the annual amortization of the reserve for injuries and damages account from an annual level of $0.670 million per year approved in the 2012/14 GRA to $0.250 million per year.

viii. To increase the annual amortization of the employee future benefits account from an annual level of $0.348 million per year approved in the 2012/14 GRA to $0.800 million per year.

ix. Amortization of deferred expenses and feasibility studies as requested.

d) ***Return on Rate Base*** of $20.214 million in 2016/17, $20.516 million in 2017/18, and $20.340 million in 2018/19 respectively, reflecting an underlying forecast capital structure financing Rate Base of approximately 40% equity and 60% long-term debt and capital lease, including the following proposed costs of capital:

i. Mid-Year Cost of Long-Term Debt of 5.53% in 2016/17, 5.36% in 2017/18 and 5.26% in 2018/19.

ii. Mid-Year Cost of Capital Lease of 9.38% in 2016/17, 9.33% in 2017/18 and 9.28% in 2018/19.

iii. A requested Return on Equity for all assets outside the Thermal Zone of 8.5%.

iv. An interest coverage ratio in the thermal zone of 1.5.

2. Approving the Forecast Test Year Rate Base at $318.753 million in 2016/17, $328.593 million in 2017/18 and $330.276 million in 2018/19 reflecting the net book value of assets in service, customer contributions, other deferred charges, and an allowance for working capital, including additions made to Rate Base pursuant to the following projects subject to PUB Project Permits:

a) ***Inuvik Gas Engines Conversion to Diesel Fuel Project*** consistent with Board Decision 22-2012.

b) ***Colville Lake Power Plant Replacement Project*** consistent with Board Decision 7-2015.

c) ***Jackfish Mirrlees Unit Replacement Project*** consistent with Board Decision 15-2015.

d) ***Snare Falls Hydro Unit Overhaul*** consistent with Board Decision 16-2015.

The Corporation is also seeking approval for the following Major Project Permits;

e) ***Snare Forks Overhaul*** in 2018/19, at a forecast cost of $7.8 million, approval for which NTPC is seeking in this Application***;***

f) ***Corporate Intelligent Metering Hub*** project for a total project cost of $4.9 million for Test Years 2017/18, 2018/19 and non-Test Years 2019/20, and 2020/21. NTPC is seeking Board approval of these costs in this Application;

g) ***Norman Wells Plant replacement project*** in 2018/19, at a forecast cost of $4.6 million, which approval NTPC is seeking in this Application.

3. **Approving rates to be charged to customers** covering the 3 Test Years as needed to achieve the full calculated level of rates ("Full Rates").

a) ***Residential Non-Government:*** Increases to all energy rates, totalling 4.8% in 2016/17, 4% in 2017/18 and 4% in 2018/19 to achieve Full Rates. No changes are proposed to fixed monthly charges.

b) ***Residential Government:*** Increases to customer energy rates equal to the same percentage as the increase in non-government customer energy

rates in the same community. No changes are proposed to fixed monthly charges.

c) ***General Service Non-Government:*** Increases to all energy rates, totalling 4.8% in 2016/17, 4% in 2017/18 and 4% in 2018/19 to achieve Full Rates. No changes are proposed to demand charges.

d) ***General Service Government*****:** Increases to customer energy rates equal to the same percentage as the increase in non-government General Service customer energy rates in the same community. No changes are proposed to demand charges.

e) ***Wholesale:*** Increases to energy rates, totalling 4.8% in 2016/17, 4% in 2017/18 and 4% in 2018/19 to achieve Full Rates. No changes to demand charges.

f) ***Industrial:*** Increases to energy rates, totalling 4.8% in 2016/17, 4% in 2017/18 and 4% in 2018/19 to achieve Full Rates. No changes to demand charges.

g) ***Lighting:*** Increases to lighting rates equal to the same percentage applied to Government General Service in the same community.

h) ***Approving 2016/17 rates as final and not subject to Phase II adjustments.*** Board Decision-7 2016 has a number of required studies and a workshop to be completed at the time of the next Phase II GRA. The Corporation expects these studies to be completed after March 31, 2017 and to promote rate stability and eliminate refund/collection riders

between customer groups, the Corporation request the 2016/17 rates be final rates.

The Corporation filed a request for interim rates effective August 1, 2016 on June 30 2016. The Corporation is requesting interim rates to increase energy charges for all customer classes in all communities by 4.8%. Consistent with the GNWT's rate policy guidelines from February 2015, the Corporation is not seeking to adjust customer charges or demand charges.

4. **Approving revised Terms and Conditions of Service** primarily focused on standardizing the Corporation's terms with normal utility provisions and to improve the clarity and consistency of the terms, as well as general housekeeping updates. As per Board Decision 8-2016 the Corporation will file an amendment to the terms and conditions relating to interruptible service at a later date.

5. **Approving a 274W, LED streetlight rate** as per the Board request on April 4, 2016.

CHAPTER 2

TARIFF, SALES AND REVENUES

2.0 TARIFF, SALES AND REVENUES

NTPC is the main generator and transmitter of power in the Northwest Territories. NTPC provides electricity at the retail level in 25 communities and at the wholesale level in two locations.

NTPC's 2016/19 GRA reflects a Revenue Requirement based on the costs to serve the loads expected to arise in those Test Years. This chapter sets out NTPC's sales and revenue forecasts for the Test Years and the methods and assumptions used to prepare those forecasts.

In accordance with the Guidelines issued by the Government of the Northwest Territories (GNWT) on July 9, 2010 and revised February 10, 2011, the forecasts have been aggregated into the following rate zones:

- Snare Zone
- Taltson Zone
- Thermal Zone

Sales and revenue forecasts at the corporate level and zone level are provided in Schedules 2.0 - 2.1.3.

2.1 SYSTEM OVERVIEW AND DEVELOPMENT SINCE THE 2012/14 GRA

2.1.1 Facilities

Retail Communities: In retail communities, NTPC supplies both generation and distribution services. Currently, of the 25 retail communities served by NTPC, 19 are served primarily by diesel generation and four are primarily served by hydro generation. The remaining two retail communities are Norman Well and Inuvik. Norman Wells is supplied primarily by purchased power priced relative to diesel fuel. Inuvik is supplied by a combination of diesel and liquefied natural gas (LNG) generation. In addition, since the last GRA, the Corporation has begun supplying part of the load in Fort Simpson and Colville Lake through solar generation to reduce the reliance on diesel generation. In 2017/18 the Corporation forecasts to start solar generation to supply part of the load in Fort Liard and Wrigley as well.

Wholesale Communities: NTPC provides bulk power from hydro generation to two wholesale customers, NUL(YK) in Yellowknife and NUL(NWT) for distribution to Hay River, Enterprise and Katlo'odeeche First Nation. In the case of NUL(YK), this power is supplemented as needed by NTPC diesel generation. For NUL(NWT), NTPC provides hydro generated power while the wholesale customer provides its own supplemental diesel generation when required. For wholesale communities, NTPC does not provide

distribution or service retail level customers directly. NTPC also supplies one industrial customer in Yellowknife.

2.1.2 Sales Trends

Table 2.1 provides a comparison of sales at the corporate and rate zone levels between the 2013/14 Test Year forecast and 2013/14 and 2014/15 actuals.

Table 2.1
System Sales – 2013/14 Test Year Forecast Compared to 2013/14 and 2014/15 Actuals

Corporate Wide Sales (MWh)	2013/14 Test Year	2013/14 Actual	*Variance Actuals to Forecasts*	2014/15 Actual	*Actual Change*
Residential	45,948	47,852	*4.1%*	45,454	*-5.0%*
General Service	61,685	60,287	*-2.3%*	58,679	*-2.7%*
Wholesale	204,315	200,870	*-1.7%*	196,845	*-2.0%*
Industrial	6,972	7,356	*5.5%*	7,680	*4.4%*
Streetlights	1,361	1,326	*-2.6%*	1,144	*-13.7%*
Total Sales	**320,282**	**317,690**	***-0.8%***	**309,803**	***-2.5%***
Snare Zone Sales (MWh)					
Residential	4,526	4,800	*6.1%*	4,688	*-2.3%*
General Service	3,834	3,556	*-7.3%*	3,520	*-1.0%*
Wholesale	171,088	168,170	*-1.7%*	165,147	*-1.8%*
Industrial	6,972	7,356	*5.5%*	7,680	*4.4%*
Streetlights	105	111	*6.0%*	138	*24.7%*
Total Sales	**186,525**	**183,993**	***-1.4%***	**181,173**	***-1.5%***
Taltson Zone Sales (MWh)					
Residential	11,654	13,408	*15.0%*	12,100	*-9.8%*
General Service	12,476	12,457	*-0.1%*	12,773	*2.5%*
Wholesale	33,227	32,700	*-1.6%*	31,698	*-3.1%*
Streetlights	331	302	*-8.8%*	276	*-8.6%*
Total Sales	**57,689**	**58,867**	***2.0%***	**56,847**	***-3.4%***
Thermal Zone Sales (MWh)					
Residential	29,767	29,644	*-0.4%*	28,666	*-3.3%*
General Service	45,375	44,274	*-2.4%*	42,386	*-4.3%*
Streetlights	925	913	*-1.3%*	730	*-20.0%*
Total Sales	**76,068**	**74,831**	***-1.6%***	**71,782**	***-4.1%***

Table 2.1 indicates that 2013/14 actual sales were within 1% of Test Year forecasts at the corporate wide level and within 2% at the rate zone level. However, 2014/15 actuals were 2.5% lower (7.9 GWh) at the corporate wide level compared to 2013/14 actuals. These reductions correspond with the substantial decrease in oil prices that began in

the summer of 2014 and the resulting economic effects on the resource sector.[1] In addition Natural Resources Canada notes the total value of mining production in the Northwest Territories was down from 1.882 billion in 2014 to $1.791 billion in 2015.[2]

The GNWT's January 2016 fiscal framework noted that the NWT is facing a range of economic challenges and forecasts modest operating surpluses in 2017 and 2018, with a small operating deficit in 2019.[3] In 2015 the Conference Board of Canada forecast average real GDP growth from 2015-2025 of approximately 1% for the NWT, which was the second lowest among Canadian provinces and territories.[4]

2.2 FORECAST METHODS FOR TEST YEARS

2.2.1 Sales Forecast

The 2016/17 to 2018/19 Test Year sales forecast was prepared consistent with the methods reviewed by the Board in the 2012/14 GRA. In Decision 1-2013, the Board directed NTPC to carry out a regression analysis for temperature sensitive sales where temperature normalization data is available. The Corporation's response to that

[1] Natural Resources Canada recorded an average monthly price for Canadian Light Sweet Crude of $105.80 per barrel in June of 2014. The average monthly price for December 2014 declined to $60.11 per barrel, a decline of 43%. Source: http://www.nrcan.gc.ca/energy/fuel-prices/crude/15085. Accessed March 15, 2016.

[2] Natural Resources Canada. 2015 Estimate of mineral production. Available: http://sead.nrcan.gc.ca/PDF/AnnPro2015-en.pdf

Accessed: April 20, 2016.

[3] 2016 GNWT Fiscal Framework. Available: http://www.gov.nt.ca/sites/default/files/GNWT%20Fiscal%20Framework%20Summary.pdf
Accessed: April 11, 2016.

[4] Presentation by Louis Theriault, Vice-President, Public Policy, The Conference Board of Canada to the NWT Chamber of Commerce. April 2015. Available: http://www.nwtchamber.com/sites/default/files/3.%20TAKING%20THE%20PULSE%20-%20CONFERENCE%20BOARD.pdf
Accessed: April 11, 2016.

directive is provided in Chapter 13 of this Application. The Corporation used weather normalized regression information in preparing its Test Year sales forecasts where reliable weather data was available. Using temperature normalization data did not materially alter the results of the forecasts compared to using a simple 5-year average use-per-customer (UPC).

The forecast residential and general service sales for the Application were prepared based on the temperature normalized average monthly UPC for the communities where reliable Heating Degree Days (HDD) data is available, and average monthly UPC for the communities where HDD data is not available, in accordance with previous Board direction. NTPC used a 5-year rolling average method to calculate UPCs for each customer class.

The load forecast for residential and general service customers was prepared in the following steps:

1. The average annual customer count is forecast based on 2015/16 actual customer counts.

2. The 5-year (April 2011 to March 2016) average temperature normalized UPC for the communities where reliable HDD data is available, and average UPC for the communities where HDD data is not available, for each month is multiplied by the forecast customer counts for each Test Year to arrive at the sales forecast.

3. A top-down review of sales forecasts is undertaken to incorporate considerations such as economic growth rates and other local knowledge.

The Snare zone wholesale forecast assumes sales will remain flat from 2015/16 full-year forecasts[5] through 2018/19 forecasts. These forecasts are roughly equivalent to 2014/15 actual results. The Taltson zone wholesale forecast assumes a 5-year rolling average based on monthly sales for the last five years.

Snare zone industrial sales are forecast to remain stable at 2015/16 full-year forecast levels based on the most recently available information about planned operations for that customer.

Forecast sales for lighting customers are estimated using the number of bulbs multiplied by average estimated usage per bulb and reflects known or planned conversions to more energy efficient lamp types.

2.2.2 Customer Forecast

The NWT Bureau of Statistics notes that territory-wide year over year population growth has been very low in recent years; specifically less than 0.3% between 2015 and 2016. On that basis the Corporation has forecast no increase in customer counts during the Test Years.[6]

[5] Includes preliminary actuals to February 2016.

[6] 2016 Population bulletin. NWT Bureau of Statistics. Available: http://www.statsnwt.ca/population/population-estimates/PopEst_Jan2016.pdf. Accessed April 8, 2016.

2.2.3 Billed Demand Forecast

The billing demand forecast for 2015/16 is based on a review of actual billing demand revenues and customer counts for 2014/15. Billing demand for the 2016/17 to 2018/19 Test Years is forecast to remain at 2015/16 levels, consistent with the forecast customer counts in the Test Years.

2.3 TEST YEAR SALES AND REVENUE FORECASTS

2.2.4 Sales Forecast Results

Table 2.2 compares 2013/14 Test Year sales forecasts to 2016/17 Test Year sales forecasts.

Table 2.2
System Sales – 2013/14 Test Year Forecast Compared to 2016/17 Test Year Forecast[7]

Corporate Wide Sales (MWh)	2013/14 Test Year	2016/17 Test Year	*Average Annual Growth*
Residential	45,948	45,781	*-0.12%*
General Service	61,685	57,886	*-2.10%*
Wholesale	204,315	195,224	*-1.51%*
Industrial	6,972	6,192	*-3.88%*
Streetlights	1,361	916	*-12.36%*
Total Sales	**320,282**	**305,999**	***-1.51%***
Snare Zone Sales (MWh)			
Residential	4,526	4,851	*2.34%*
General Service	3,834	3,427	*-3.68%*
Wholesale	171,088	163,417	*-1.52%*
Industrial	6,972	6,192	*-3.88%*
Streetlights	105	70	*-12.49%*
Total Sales	**186,525**	**177,957**	***-1.56%***
Taltson Zone Sales (MWh)			
Residential	11,654	12,182	*1.49%*
General Service	12,476	12,828	*0.93%*
Wholesale	33,227	31,807	*-1.45%*
Streetlights	331	260	*-7.75%*
Total Sales	**57,689**	**57,076**	***-0.36%***
Thermal Zone Sales (MWh)			
Residential	29,767	28,748	*-1.15%*
General Service	45,375	41,631	*-2.83%*
Streetlights	925	586	*-14.12%*
Total Sales	**76,068**	**70,965**	***-2.29%***

Total forecast sales for 2016/17 are lower relative to the 2013/14 Test Year forecast (14.3 GWh), with an average annual decline in sales of 1.5%. The decrease in total

[7] 2013/14 Test Year information is based on 2014 Phase II GRA updated filing schedules.

sales arises primarily in the Snare zone (8.6 GWh lower) and the Thermal zone (5.1 GWh lower). Sales are forecast to be relatively flat in the Taltson zone from 2013/14 Test Year forecasts to 2016/17 Test Year forecasts.

Declining sales are forecast in the wholesale rate class (9.1 GWh decrease), General Service rate class (3.8 GWh decrease) and Industrial rate class (0.8 GWh). Residential sales at a corporate wide level are expected to remain relatively flat, while decreased sales of 0.4 GWh in the Street lighting class are driven primarily by the conversion to LED streetlights.

On the Snare system, most of the decreases are related to decreased sales to the wholesale customer and the industrial customer. The residential class is forecast to have slightly higher sales in 2016/17 compared to 2013/14. Sales to general service customers are forecast to be somewhat lower in 2016/17 compared to 2013/14.

In the Taltson zone, sales are forecast to be relatively flat for 2016/17 compared to 2013/14. Decreases in sales to the wholesale customer are forecast (1.4 GWh lower in 2016/17 compared to 2013/14 forecasts). These lower forecasts for wholesale sales in 2016/17 are consistent with the decrease in actual sales from 2013/14 to 2014/15. Modest growth is forecast for residential sales (0.5 GWh) and general service sales (0.4 GWh) reflecting higher average use per customer.

The forecast sales decreases in the Thermal zone largely reflect decreased sales to general service customers (3.7 GW.h lower compared to 2013/14 forecasts). These decreases are consistent with actual decreases between 2013/14 and 2014/15 and

reflect lower average use per customer. Sales decreases for residential customers also reflect somewhat lower average use per customer. Sales decreases for street lighting customers reflect the conversion of streetlights from mercury vapour and high pressure sodium lamps to LED.

Sales at the corporate level are forecast to show very little growth from 2016/17 to 2017/18 (0.3GWh) and from 2017/18 to 2018/19 (0.01 GWh). This forecast is consistent with economic growth expectations for the NWT during this time period.

2.2.5 Revenue Forecast Results

Forecast energy sales for residential and general service customers are split into government and non-government sales for revenue forecasting purposes. The forecast split between government and non-government sales for the Test Years was prepared based on actual billing data for the 2014/15 fiscal year.

Table 2.3
Revenue Forecast – 2013/14 Test Year Compared to 2016/17 Test Year Forecast

Corporate Wide	2013/14 Test Year	2016/17 Test Year	*Average Annual Growth*
Residential	25,924	25,843	*-0.10%*
General Service	36,762	34,663	*-1.94%*
Wholesale	39,459	37,654	*-1.55%*
Industrial	1,231	1,174	*-1.57%*
Streetlights	1,461	867	*-15.97%*
Total Revenue	**104,836**	**100,201**	***-1.50%***
Snare Zone			
Residential	1,552	1,664	*2.36%*
General Service	1,646	1,482	*-3.44%*
Wholesale	35,903	34,245	*-1.56%*
Industrial	1,231	1,174	*-1.57%*
Streetlights	94	63	*-12.37%*
Total Revenue	**40,426**	**38,629**	***-1.50%***
Taltson Zone			
Residential	2,738	2,856	*1.41%*
General Service	2,522	2,612	*1.18%*
Wholesale	3,556	3,409	*-1.40%*
Streetlights	112	84	*-9.01%*
Total Revenue	**8,928**	**8,961**	***0.12%***
Thermal Zone			
Residential	21,634	21,323	*-0.48%*
General Service	32,594	30,569	*-2.12%*
Streetlights	1,255	719	*-16.93%*
Total Revenue	**55,483**	**52,611**	***-1.76%***

Overall revenue decreases from the 2013/14 Test Year to the 2016/17 Test Year are due to reductions in sales. Revenues at existing rates are forecast to change by only small amounts in each Test Year due to relatively flat sales forecasts.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
SUMMARY OF GENERATION, SALES, AND REVENUE
NTPC SUMMARY

Line no.	Description	2013/14 Test Year	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast @ Existing Rates	2017/18 Forecast @ Existing Rates	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE							
	Residential							
1	Sales (MWh)	45,948	47,852	45,454	44,320	45,781	45,864	45,834
2	Customers	6,716	6,706	6,692	6,739	6,739	6,739	6,739
3	Av. MWh Sales/Cust.	6.84	7.14	6.79	6.58	6.79	6.81	6.80
4	Revenue (000s)	25,924	22,905	24,536	25,310	25,843	25,872	25,856
5	Cents /kWh	56.42	47.87	53.98	57.11	56.45	56.41	56.41
	General Service							
6	Sales (MWh)	61,685	60,287	58,679	57,987	57,886	58,116	58,148
7	Customers	1,937	1,861	1,862	1,876	1,876	1,876	1,876
8	Av. MWh Sales/Cust.	31.85	32.39	31.51	30.91	30.86	30.98	31.00
9	Revenue (000s)	36,762	31,654	33,882	34,849	34,663	34,823	34,844
10	Cents /kWh	59.60	52.50	57.74	60.10	59.88	59.92	59.92
	Wholesale							
11	Sales (MWh)	204,315	200,870	196,845	194,460	195,224	195,218	195,227
12	Customers	2	2	2	2	2	2	2
13	Revenue (000s)	39,459	34,428	36,247	37,664	37,654	37,654	37,655
14	Cents /kWh	19.31	17.14	18.41	19.37	19.29	19.29	19.29
	Industrial							
15	Sales (MWh)	6,972	7,356	7,680	6,192	6,192	6,192	6,192
16	Customers	2	1	1	1	1	1	1
17	Av. MWh Sales/Cust.	3486	7356	7680	6192	6192	6192	6192
18	Revenue (000s)	1,231	1,294	1,333	1,170	1,174	1,174	1,174
19	Cents /kWh	17.66	17.59	17.36	18.90	18.96	18.96	18.96
	Streetlights							
20	Sales (MWh)	1,361	1,326	1,144	988	916	916	916
21	Revenue (000s)	1,461	1,353	1,262	838	867	867	867
22	Cents /kWh	107.34	102.10	110.31	84.84	94.63	94.63	94.63
	Total Community							
23	**Sales (MWh)**	**320,282**	**317,690**	**309,803**	**303,947**	**305,999**	**306,305**	**306,317**
24	Customers	**8,657**	**8,570**	**8,557**	**8,618**	**8,618**	**8,618**	**8,618**
25	Revenue (000s)	**104,836**	**91,634**	**97,261**	**99,832**	**100,201**	**100,389**	**100,396**
26	Cents /kWh	32.73	28.84	31.39	32.85	32.75	32.77	32.78
	GENERATION (MWh)							
27	**Total Station Service**	13,174	14,281	12,425	13,318	13,522	13,771	13,512
28	**Total Losses**	17,872	16,013	13,829	15,825	15,421	15,485	15,617
29	***Losses - % of Gen.***	*5.1%*	*4.6%*	*4.1%*	*4.8%*	*4.6%*	*4.6%*	*4.7%*
30	**Total Generation**	**351,327**	**347,985**	**336,057**	**333,090**	**334,941**	**335,561**	**335,446**
	Source (MWh)							
31	Hydro Generation	264,815	260,977	203,838	181,474	249,931	250,321	250,085
32	Gas Generation	13,249	1,348	8,945	8,635	11,330	11,347	11,346
33	Gas Efficiency	3.356	2.579	3.725	3.340			
34	*Cubic Meters (000s)*	3,948	523	2,401	2,585	3,392	3,397	3,397
35	Diesel Generation	64,929	75,611	113,431	133,536	63,810	63,970	64,101
36	Diesel Efficiency	3.554	3.518	3.635	3.597	3.587	3.587	3.598
37	*Liters (000s)*	*18,271*	*21,495*	*31,204*	*37,124*	*17,787*	*17,833*	*17,814*
38	Solar Generation			6	53	212	250	250
39	Purchased Power	8,335	10,049	9,836	9,292	9,658	9,674	9,664
40	Total Generation	351,327	347,985	336,057	332,990	334,941	335,561	335,446
	% of Total Generation							
41	Hydro	*75.4%*	*75.0%*	*60.7%*	*54.5%*	*74.6%*	*74.6%*	*74.6%*
42	Gas	*3.8%*	*0.4%*	*2.7%*	*2.6%*	*3.4%*	*3.4%*	*3.4%*
43	Diesel	*18.5%*	*21.7%*	*33.8%*	*40.1%*	*19.1%*	*19.1%*	*19.1%*
44	Solar			*0.0%*	*0.0%*	*0.1%*	*0.1%*	*0.1%*
45	Purchased	*2.4%*	*2.9%*	*2.9%*	*2.8%*	*2.9%*	*2.9%*	*2.9%*
	Peak (kW)							
46	Total Peak	66,195	64,464	61,394	63,039	63,005	62,885	62,812
47	Load Factor	60.6%	61.6%	62.5%	60.3%	60.7%	60.9%	61.0%

Notes:

1. Sales and Revenues for 2013/14 Test Year reflect 2012-14 GRA Phase I approved sales and rates effective April 1, 2015 with the sales adjustment to move Miramar Con mine sales from Industrial to Wholesale rate class

NORTHWEST TERRITORIES POWER CORPORATION
2017 - 2019 GENERAL RATE APPLICATION
SUMMARY OF GENERATION, SALES, AND REVENUE
SNARE ZONE

Line no.	Description	2013/14 Test Year	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast @ Existing Rates	2017/18 Forecast @ Existing Rates	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE							
	Residential							
1	Sales (MWh)	4,526	4,800	4,688	4,484	4,851	4,836	4,785
2	Customers	572	607	607	611	611	611	611
3	Av. MWh Sales/Cust.	7.91	7.91	7.72	7.34	7.94	7.91	7.83
4	Revenue (000s)	1,552	1,523	1,458	1,548	1,664	1,659	1,643
5	Cents /kWh	34.28	31.72	31.10	34.52	34.31	34.32	34.34
	General Service							
6	Sales (MWh)	3,834	3,556	3,520	3,474	3,427	3,454	3,496
7	Customers	126	123	126	126	126	126	126
8	Av. MWh Sales/Cust.	30.43	28.91	27.93	27.57	27.19	27.41	27.74
9	Revenue (000s)	1,646	1,418	1,396	1,499	1,482	1,493	1,509
10	Cents /kWh	42.94	39.88	39.65	43.15	43.26	43.21	43.17
	Wholesale							
11	Sales (MWh)	171,088	168,170	165,147	163,417	163,417	163,417	163,417
12	Customers	1	1	1	1	1	1	1
13	Revenue (000s)	35,903	31,376	32,995	34,338	34,245	34,245	34,245
14	Cents /kWh	20.98	18.66	19.98	21.01	20.96	20.96	20.96
	Industrial							
15	Sales (MWh)	6,972	7,356	7,680	6,192	6,192	6,192	6,192
16	Customers	2	1	1	1	1	1	1
17	Av. MWh Sales/Cust.	3486	7,356	7,680	6,192	6,192	6,192	6,192
18	Revenue (000s)	1,231	1,294	1,333	1,170	1,174	1,174	1,174
19	Cents /kWh	17.66	17.59	17.36	18.90	18.96	18.96	18.96
	Streetlights							
20	Sales (MWh)	105	111	138	138	70	70	70
21	Revenue (000s)	94	99	117	62	63	63	63
22	Cents /kWh	90.07	89.42	84.40	44.75	90.45	90.45	90.45
	Total Community							
23	**Sales (MWh)**	**186,525**	**183,993**	**181,173**	**177,705**	**177,957**	**177,969**	**177,960**
24	Customers	**701**	**732**	**735**	**739**	**739**	**739**	**739**
25	Revenue (000s)	**40,426**	**35,710**	**37,299**	**38,617**	**38,629**	**38,634**	**38,635**
26	Cents /kWh	21.67	19.41	20.59	21.73	21.71	21.71	21.71
	GENERATION (MWh)							
27	**Total Station Service**	7,966	8,489	7,163	8,110	8,199	8,457	8,156
28	**Total Losses**	5,649	6,954	3,246	5,332	5,101	5,327	5,542
29	***Losses - % of Gen.***	*2.8%*	*3.5%*	*1.7%*	*2.8%*	*2.7%*	*2.8%*	*2.9%*
30	**Total Generation**	**200,141**	**199,436**	**191,582**	**191,148**	**191,257**	**191,753**	**191,657**
	Source (MWh)							
31	Hydro Generation	198,941	195,043	142,178	120,023	186,257	186,753	186,657
32	Gas Generation							
33	Gas Efficiency							
34	*Cubic Meters (000s)*							
35	Diesel Generation	1,200	4,393	49,404	71,125	5,000	5,000	5,000
36	Diesel Efficiency	3.650	3.618	3.662	3.610	3.610	3.610	3.610
37	*Liters (000s)*	*329*	*1,214*	*13,490*	*19,702*	*1,385*	*1,385*	*1,385*
38	Solar Generation							
39	Purchased Power							
40	Total Generation	200,141	199,436	191,582	191,148	191,257	191,753	191,657
	% of Total Generation							
41	Hydro	*99.4%*	*97.8%*	*74.2%*	*62.8%*	*97.4%*	*97.4%*	*97.4%*
42	Gas							
43	Diesel	*0.6%*	*2.2%*	*25.8%*	*37.2%*	*2.6%*	*2.6%*	*2.6%*
44	Solar							
45	Purchased							
	Peak (kW)							
46	Total Peak	37,677	35,800	33,000	34,267	34,261	34,112	34,032
47	Load Factor	60.6%	63.6%	66.3%	63.7%	63.7%	64.2%	64.3%

Notes:
1. Sales and Revenues for 2013/14 Test Year reflect 2012-14 GRA Phase I approved sales and rates effective April 1, 2015 with the sales adjustment to move Miramar Con mine sales from Industrial to Wholesale rate class

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
SUMMARY OF GENERATION, SALES, AND REVENUE
TALTSON ZONE

Line no.	Description	2013/14 Test Year	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast @ Existing Rates	2017/18 Forecast @ Existing Rates	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE							
	Residential							
1	Sales (MWh)	11,654	13,408	12,100	11,400	12,182	12,255	12,290
2	Customers	1,254	1,270	1,268	1,268	1,268	1,268	1,268
3	Av. MWh Sales/Cust.	9.29	10.56	9.54	8.99	9.61	9.66	9.69
4	Revenue (000s)	2,738	2,589	2,709	2,690	2,856	2,871	2,879
5	Cents /kWh	23.49	19.31	22.38	23.60	23.44	23.43	23.42
	General Service							
6	Sales (MWh)	12,476	12,457	12,773	12,503	12,828	12,815	12,808
7	Customers	289	288	290	297	297	297	297
8	Av. MWh Sales/Cust.	43.17	43.25	44.04	42.10	43.19	43.15	43.12
9	Revenue (000s)	2,522	2,285	2,473	2,558	2,612	2,610	2,609
10	Cents /kWh	20.21	18.34	19.36	20.46	20.36	20.36	20.37
	Wholesale							
11	Sales (MWh)	33,227	32,700	31,698	31,043	31,807	31,801	31,810
12	Customers	1	1	1	1	1	1	1
13	Revenue (000s)	3,556	3,052	3,252	3,326	3,409	3,408	3,409
14	Cents /kWh	10.70	9.33	10.26	10.72	10.72	10.72	10.72
	Industrial							
15	Sales (MWh)							
16	Customers							
17	Av. MWh Sales/Cust.							
18	Revenue (000s)							
19	Cents /kWh							
	Streetlights							
20	Sales (MWh)	331	302	276	276	260	260	260
21	Revenue (000s)	112	122	127	83	84	84	84
22	Cents /kWh	33.76	40.47	46.18	30.04	32.40	32.40	32.40
	Total Community							
23	**Sales (MWh)**	**57,689**	**58,867**	**56,847**	**55,222**	**57,076**	**57,130**	**57,167**
24	Customers	**1,544**	**1,559**	**1,559**	**1,566**	**1,566**	**1,566**	**1,566**
25	Revenue (000s)	**8,928**	**8,049**	**8,561**	**8,658**	**8,961**	**8,973**	**8,981**
26	Cents /kWh	15.48	13.67	15.06	15.68	15.70	15.71	15.71
	GENERATION (MWh)							
27	**Total Station Service**	1,789	1,924	1,731	1,872	1,928	1,868	1,888
28	**Total Losses**	7,360	5,956	4,243	5,902	5,794	5,705	5,528
29	***Losses - % of Gen.***	*11.0%*	*8.9%*	*6.8%*	*9.4%*	*8.9%*	*8.8%*	*8.6%*
30	**Total Generation**	**66,837**	**66,747**	**62,822**	**62,997**	**64,798**	**64,703**	**64,583**
	Source (MWh)							
31	Hydro Generation	65,874	65,934	61,661	61,451	63,675	63,568	63,428
32	Gas Generation							
33	Gas Efficiency							
34	*Cubic Meters (000s)*							
35	Diesel Generation	964	813	1,161	1,546	1,123	1,135	1,156
36	Diesel Efficiency	3.458	3.456	3.228	3.408	3.405	3.405	3.404
37	*Liters (000s)*	*279*	*235*	*360*	*454*	*330*	*333*	*339*
38	Solar Generation							
39	Purchased Power							
40	Total Generation	66,837	66,747	62,822	62,997	64,798	64,703	64,583
	% of Total Generation							
41	Hydro	*98.6%*	*98.8%*	*98.2%*	*97.5%*	*98.3%*	*98.2%*	*98.2%*
42	Gas							
43	Diesel	*1.4%*	*1.2%*	*1.8%*	*2.5%*	*1.7%*	*1.8%*	*1.8%*
44	Solar							
45	Purchased							
	Peak (kW)							
46	Total Peak	13,269	13,732	12,846	12,947	13,208	13,225	13,225
47	Load Factor	57.5%	55.5%	55.8%	55.5%	56.0%	55.9%	55.7%

1. Sales and Revenues for 2013/14 Test Year reflect 2012-14 GRA Phase I approved sales and rates effective April 1, 2015 with the sales adjustment to move Miramar Con mine sales from Industrial to Wholesale rate class

NORTHWEST TERRITORIES POWER CORPORATION
2017 - 2019 GENERAL RATE APPLICATION
SUMMARY OF GENERATION, SALES, AND REVENUE
THERMAL ZONE

Line no.	Description	2013/14 Test Year	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast @ Existing Rates	2017/18 Forecast @ Existing Rates	2018/19 Forecast @ Existing Rates
	SALES AND REVENUE							
	Residential							
1	Sales (MWh)	29,767	29,644	28,666	28,436	28,748	28,773	28,759
2	Customers	4,890	4,829	4,817	4,860	4,860	4,860	4,860
3	Av. MWh Sales/Cust.	6.09	6.14	5.95	5.85	5.92	5.92	5.92
4	Revenue (000s)	21,634	18,793	20,369	21,072	21,323	21,341	21,335
5	Cents /kWh	72.68	63.40	71.06	74.10	74.17	74.17	74.18
	General Service							
6	Sales (MWh)	45,375	44,274	42,386	42,010	41,631	41,847	41,844
7	Customers	1,522	1,450	1,446	1,453	1,453	1,453	1,453
8	Av. MWh Sales/Cust.	29.81	30.53	29.31	28.91	28.65	28.80	28.80
9	Revenue (000s)	32,594	27,950	30,013	30,792	30,569	30,721	30,726
10	Cents /kWh	71.83	63.13	70.81	73.30	73.43	73.41	73.43
	Wholesale							
11	Sales (MWh)							
12	Customers							
13	Revenue (000s)							
14	Cents /kWh							
	Industrial							
15	Sales (MWh)							
16	Customers							
17	Av. MWh Sales/Cust.							
18	Revenue (000s)							
19	Cents /kWh							
	Streetlights							
20	Sales (MWh)	925	913	730	574	586	586	586
21	Revenue (000s)	1,255	1,132	1,018	694	719	719	719
22	Cents /kWh	135.61	124.01	139.46	120.87	122.71	122.71	122.71
	Total Community							
23	**Sales (MWh)**	**76,068**	**74,831**	**71,782**	**71,020**	**70,965**	**71,206**	**71,189**
24	Customers	**6,412**	**6,279**	**6,263**	**6,313**	**6,313**	**6,313**	**6,313**
25	Revenue (000s)	**55,483**	**47,876**	**51,401**	**52,558**	**52,611**	**52,781**	**52,780**
26	Cents /kWh	72.94	63.98	71.61	74.00	74.14	74.12	74.14
	GENERATION (MWh)							
27	**Total Station Service**	3,418	3,868	3,531	3,335	3,395	3,445	3,469
28	**Total Losses**	4,863	3,103	6,340	4,591	4,526	4,453	4,547
29	***Losses - % of Gen.***	*5.8%*	*3.8%*	*7.8%*	*5.8%*	*5.7%*	*5.6%*	*5.7%*
30	**Total Generation**	**84,349**	**81,802**	**81,653**	**78,946**	**78,887**	**79,105**	**79,205**
	Source (MWh)							
31	Hydro Generation							
32	Gas Generation	13,249	1,348	8,945	8,635	11,330	11,347	11,346
33	Gas Efficiency	3.356	2.579	3.725	3.340	3.340	3.340	3.340
34	*Cubic Meters (000s)*	*3,948*	*523*	*2,401*	*2,585*	*3,392*	*3,397*	*3,397*
35	Diesel Generation	62,766	70,404	62,866	60,866	57,687	57,835	57,945
36	Diesel Efficiency	3.553	3.512	3.623	3.587	3.589	3.589	3.601
37	*Liters (000s)*	*17,663*	*20,045*	*17,354*	*16,969*	*16,073*	*16,115*	*16,089*
38	Solar Generation			6	53	212	250	250
39	Purchased Power	8,335	10,049	9,836	9,292	9,658	9,674	9,664
40	Total Generation	84,349	81,802	81,653	78,846	78,887	79,105	79,205
	% of Total Generation							
41	Hydro							
42	Gas	*15.7%*	*1.6%*	*11.0%*	*10.9%*	*14.4%*	*14.3%*	*14.3%*
43	Diesel	*74.4%*	*86.1%*	*77.0%*	*77.1%*	*73.1%*	*73.1%*	*73.2%*
44	Solar			*0.0%*	*0.1%*	*0.3%*	*0.3%*	*0.3%*
45	Purchased	*9.9%*	*12.3%*	*12.0%*	*11.8%*	*12.2%*	*12.2%*	*12.2%*
	Peak (kW)							
46	Total Peak	15,248	14,932	15,548	15,825	15,536	15,548	15,554
47	Load Factor	63.1%	62.5%	60.0%	56.9%	58.0%	58.1%	58.1%

1. Sales and Revenues for 2013/14 Test Year reflect 2012-14 GRA Phase I approved sales and rates effective April 1, 2015 with the sales adjustment to move Miramar Con mine sales from Industrial to Wholesale rate class

Schedule 2.2-1

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Load Forecast Illustration for Representative Sample of Communities

Line no.	Description	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Fort Smith								
	Residential								
1	Total Sales (MWh)	10,035	10,507	11,694	10,519	9,890	10,588	10,651	10,679
2	Average Number of Customers	1,033	1,033	1,054	1,051	1,047	1,047	1,047	1,047
3	Usage Per Customer (UPC)	9.71	10.17	11.09	10.01	9.45	10.11	10.17	10.20
4	Weather Normalized UPC	9.82	10.04	10.93	10.18	9.60	10.11	10.17	10.20
5	Adjustments to Forecast								
6	Total Sales after Adjustments (MWh)					9,890	10,588	10,651	10,679
	General Service								
7	Total Sales (MWh)	11,320	11,448	11,436	11,687	11,393	11,719	11,703	11,687
8	Average Number of Customers	218	218	221	224	226	226	226	226
9	Usage Per Customer (UPC)	51.93	52.51	51.75	52.17	50.41	51.86	51.78	51.71
10	Weather Normalized UPC	52.23	52.12	51.23	52.80	50.90	51.86	51.78	51.71
11	Adjustments to Forecast								
12	Total Sales after Adjustments (MWh)					11,393	11,719	11,703	11,687
	Ford Liard								
	Residential								
13	Total Sales (MWh)	1,017	1,016	978	994	964	1,001	997	996
14	Average Number of Customers	186	186	186	181	186	186	186	186
15	Usage Per Customer (UPC)	5.47	5.46	5.26	5.49	5.18	5.38	5.36	5.35
16	Weather Normalized UPC	5.48	5.39	5.23	5.45	5.35	5.38	5.36	5.35
17	Adjustments to Forecast								
18	Total Sales after Adjustments (MWh)					964	1,001	997	996
	General Service								
19	Total Sales (MWh)	1,368	1,259	1,176	1,170	1,105	1,114	1,113	1,129
20	Average Number of Customers	50	50	40	38	41	41	41	41
21	Usage Per Customer (UPC)	27.36	25.18	29.39	30.80	26.95	27.17	27.14	27.54
22	Weather Normalized UPC	27.37	25.10	25.26	30.66	27.48	27.17	27.14	27.54
23	Adjustments to Forecast								
24	Total Sales after Adjustments (MWh)					1,105	1,114	1,113	1,129
	Inuvik								
	Residential								
25	Total Sales (MWh)	8,469	8,481	8,400	7,799	7,958	8,067	8,064	8,048
26	Average Number of Customers	1,403	1,412	1,364	1,364	1,362	1,362	1,362	1,362
27	Usage Per Customer (UPC)	6.04	6.01	6.16	5.72	5.84	5.92	5.92	5.91
28	Weather Normalized UPC	5.93	5.98	6.03	5.76	5.91	5.92	5.92	5.91
29	Adjustments to Forecast						-3%	-3%	-3%
30	Total Sales after Adjustments (MWh)					7,958	7,825	7,823	7,807
	General Service								
31	Total Sales (MWh)	19,505	19,881	18,919	17,468	17,909	17,778	17,822	17,793
32	Average Number of Customers	476	477	431	432	432	432	432	432
33	Usage Per Customer (UPC)	40.98	41.68	43.90	40.43	41.46	41.15	41.26	41.19
34	Weather Normalized UPC	40.64	41.60	41.05	40.65	41.83	41.15	41.26	41.19
35	Adjustments to Forecast						-3%	-3%	-3%
36	Total Sales after Adjustments (MWh)					17,909	17,245	17,288	17,259

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
UPC WEATHER NORMALIZATION

Schedule 2.2-2

	Month	Fort Smith				Historical HDD		5-year average HDD
		General Service		Residential				
		Actual UPC	Weather Normalized UPC	Actual UPC	Weather Normalized UPC			
Actual	Apr-11	4,236	4,226	856	852	621.6	April	612.8
	May-11	3,911	3,948	687	699	230.5	May	261.2
	Jun-11	4,058	4,022	626	614	113.2	June	83.5
	Jul-11	3,517	3,535	616	622	21.5	July	36.4
	Aug-11	3,725	3,718	624	622	81.4	August	76.2
	Sep-11	3,847	3,885	689	702	196.6	September	227.7
	Oct-11	3,847	3,892	705	720	483.3	October	520.7
	Nov-11	4,675	4,492	931	870	893.3	November	742.3
	Dec-11	4,669	4,875	873	942	996.6	December	1,166.4
	Jan-12	5,624	5,656	1,208	1,218	1,178.4	January	1,204.0
	Feb-12	5,958	6,087	1,029	1,072	936.9	February	1,043.4
	Mar-12	3,860	3,892	872	882	932.3	March	958.5
	Apr-12	4,676	4,733	831	850	565.7		
	May-12	3,948	3,993	707	722	223.7		
	Jun-12	3,626	3,630	602	603	80.1		
	Jul-12	3,804	3,840	615	627	7.1		
	Aug-12	3,793	3,822	618	628	52.5		
	Sep-12	4,064	4,114	705	722	186.1		
	Oct-12	3,548	3,464	696	668	589.8		
	Nov-12	4,520	4,231	940	844	980.2		
	Dec-12	5,105	4,938	1,084	1,028	1,304.4		
	Jan-13	5,723	5,610	1,254	1,216	1,296.9		
	Feb-13	5,485	5,605	1,138	1,178	944.6		
	Mar-13	4,221	4,142	980	953	1,023.7		
	Apr-13	4,672	4,565	1,761	1,725	701.0		
	May-13	3,714	3,744	705	715	236.0		
	Jun-13	4,096	4,132	674	686	54.2		
	Jul-13	3,879	3,827	622	605	79.1		
	Aug-13	3,633	3,643	666	669	68.2		
	Sep-13	3,935	3,979	691	706	191.2		
	Oct-13	3,833	3,854	764	771	502.9		
	Nov-13	4,350	4,105	921	839	944.5		
	Dec-13	4,863	4,591	1,057	966	1,390.3		
	Jan-14	5,757	5,685	1,229	1,205	1,263.5		
	Feb-14	5,304	5,174	1,129	1,085	1,151.1		
	Mar-14	4,099	3,936	1,011	957	1,092.4		
	Apr-14	4,938	4,879	910	891	661.5		
	May-14	3,909	3,801	723	687	349.5		
	Jun-14	3,869	3,871	649	649	81.8		
	Jul-14	3,635	3,651	635	641	23.7		
	Aug-14	3,833	3,802	658	648	101.5		
	Sep-14	3,735	3,648	622	593	299.4		
	Oct-14	2,921	2,943	800	807	502.6		
	Nov-14	4,988	5,772	898	1,161	96.6		
	Dec-14	4,686	4,734	1,014	1,029	1,127.5		
	Jan-15	5,678	5,659	1,139	1,133	1,219.3		
	Feb-15	5,259	5,128	1,014	971	1,150.9		
	Mar-15	4,827	4,911	943	971	889.5		
	Apr-15	3,935	4,054	788	828	514.4		
	May-15	3,657	3,651	636	634	266.1		
	Jun-15	4,184	4,179	614	612	88.2		
	Jul-15	2,649	2,632	555	549	50.6		
	Aug-15	4,409	4,407	690	690	77.6		
	Sep-15	3,612	3,567	617	602	265.3		
	Oct-15	3,694	3,689	699	697	524.8		
	Nov-15	4,954	4,887	934	911	796.7		
	Dec-15	5,066	5,252	884	947	1,013.0		
	Jan-16	4,862	5,035	1,061	1,118	1,061.8		
	Feb-16	5,030	5,042	991	995	1,033.4		
Forecast	Mar-16	4,375	4,502	975	1,017	854.4		

Forecast (5-year rolling average)

	General Service Weather Normalized Rolling Average UPC	Residential Weather Normalized Rolling Average UPC
Apr-16	4,491	1,029
May-16	3,828	692
Jun-16	3,967	633
Jul-16	3,497	609
Aug-16	3,878	651
Sep-16	3,839	665
Oct-16	3,568	733
Nov-16	4,698	925
Dec-16	4,878	983
Jan-17	5,529	1,178
Feb-17	5,407	1,060
Mar-17	4,276	956
Apr-17	4,545	1,065
May-17	3,804	690
Jun-17	3,956	637
Jul-17	3,489	606
Aug-17	3,910	657
Sep-17	3,829	658
Oct-17	3,504	735
Nov-17	4,739	936
Dec-17	4,878	991
Jan-18	5,504	1,170
Feb-18	5,271	1,058
Mar-18	4,353	971
Apr-18	4,507	1,108
May-18	3,766	684
Jun-18	4,021	644
Jul-18	3,419	602
Aug-18	3,928	663
Sep-18	3,772	645
Oct-18	3,511	749
Nov-18	4,840	954
Dec-18	4,867	983
Jan-19	5,482	1,161
Feb-19	5,204	1,034
Mar-19	4,396	974

Regression Analysis **Schedule 2.2-2**
Fort Smith
General Service
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.74347864
R Square	0.552760488
Adjusted R Square	0.545049462
Standard Error	487.5943744
Observations	60

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	17042848.88	17042848.88	71.68442738	1.01642E-11
Residual	58	13789399.89	237748.274		
Total	59	30832248.77			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	3619.619191	104.0728742	34.77966012	1.51656E-40	3411.294699	3827.943683	3411.294699	3827.943683
X Variable 1	1.214536937	0.143449262	8.466665659	1.01642E-11	0.927392042	1.501681832	0.927392042	1.501681832

Fort Smith
Residential
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.80014952
R Square	0.640239254
Adjusted R Square	0.634036482
Standard Error	135.9844926
Observations	60

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1908689.51	1908689.51	103.2182558	1.7203E-14
Residual	58	1072523.37	18491.78224		
Total	59	2981212.88			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	607.934119	29.02473395	20.94538128	9.927E-29	549.8348016	666.0334364	549.8348016	666.0334364
X Variable 1	0.406450137	0.040006358	10.15963857	1.7203E-14	0.326368711	0.486531563	0.326368711	0.486531563

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
UPC WEATHER NORMALIZATION

Schedule 2.2-3

	Month	Inuvik				Historical HDD		5-year average HDD
		General Service		Residential				
		Actual UPC	Weather Normalized UPC	Actual UPC	Weather Normalized UPC			
Actual	Apr-11	3,502	3,437	578	557	995.4	April	889.0
	May-11	2,881	2,867	412	408	500.3	May	478.3
	Jun-11	3,089	3,051	379	367	250.8	June	189.2
	Jul-11	2,989	3,010	390	397	80.3	July	114.8
	Aug-11	3,386	3,387	430	430	202.8	August	204.7
	Sep-11	3,269	3,275	444	446	380.4	September	390.0
	Oct-11	3,099	3,086	491	487	693.4	October	671.1
	Nov-11	3,470	3,386	562	536	1,185.8	November	1,047.0
	Dec-11	3,538	3,575	536	548	1,220.9	December	1,280.6
	Jan-12	4,323	4,268	666	648	1,387.7	January	1,296.3
	Feb-12	4,418	4,436	585	591	1,126.9	February	1,156.9
	Mar-12	3,012	2,866	562	516	1,429.7	March	1,189.9
	Apr-12	3,648	3,674	578	586	846.8		
	May-12	3,016	2,999	416	411	505.7		
	Jun-12	3,159	3,195	347	358	129.7		
	Jul-12	2,562	2,603	377	390	47.8		
	Aug-12	4,063	4,111	424	439	126.6		
	Sep-12	3,621	3,671	439	455	308.1		
	Oct-12	3,184	3,193	479	481	657.1		
	Nov-12	3,444	3,428	528	523	1,073.2		
	Dec-12	4,035	3,965	548	526	1,396.2		
	Jan-13	3,583	3,511	652	630	1,414.5		
	Feb-13	3,948	3,867	610	584	1,290.4		
	Mar-13	3,415	3,380	609	598	1,247.4		
	Apr-13	4,211	4,122	677	649	1,035.1		
	May-13	2,812	2,739	408	386	597.8		
	Jun-13	3,265	3,265	369	369	189.3		
	Jul-13	2,968	2,958	372	369	131.6		
	Aug-13	2,969	2,966	407	406	209.6		
	Sep-13	3,412	3,404	452	449	404.5		
	Oct-13	2,860	2,940	467	493	538.2		
	Nov-13	3,128	3,182	520	537	958.1		
	Dec-13	4,050	4,049	555	555	1,281.9		
	Jan-14	5,143	5,159	648	654	1,269.6		
	Feb-14	4,350	4,350	628	628	1,155.8		
	Mar-14	1,866	1,917	520	536	1,105.8		
	Apr-14	3,166	3,206	423	436	823.7		
	May-14	2,892	2,910	377	383	448.6		
	Jun-14	3,418	3,426	370	372	175.3		
	Jul-14	2,896	2,877	373	367	145.5		
	Aug-14	3,445	3,429	419	414	230.9		
	Sep-14	3,275	3,268	432	430	401.5		
	Oct-14	3,316	3,278	484	473	732.6		
	Nov-14	3,659	3,659	532	532	1,046.7		
	Dec-14	3,805	3,842	556	567	1,220.9		
	Jan-15	3,967	3,976	652	655	1,282.0		
	Feb-15	3,934	3,990	600	617	1,065.5		
	Mar-15	2,728	2,788	498	517	1,090.6		
	Apr-15	3,939	4,027	545	573	743.9		
	May-15	2,810	2,895	390	417	339.1		
	Jun-15	3,291	3,284	352	350	200.8		
	Jul-15	2,443	2,410	364	354	169.0		
	Aug-15	3,676	3,646	440	431	253.6		
	Sep-15	3,312	3,272	434	421	455.3		
	Oct-15	3,269	3,230	453	441	734.4		
	Nov-15	4,094	4,140	566	581	971.0		
	Dec-15	3,927	3,925	550	550	1,283.2		
	Jan-16	4,246	4,348	669	701	1,127.9		
	Feb-16	3,847	3,854	565	567	1,145.7		
Forecast	Mar-16	2,725	2,794	504	526	1,075.9		

Forecast (5-year rolling average)

Schedule 2.2-3

	General Service Weather Normalized Rolling Average UPC	Residential Weather Normalized Rolling Average UPC
Apr-16	3,693	560
May-16	2,882	401
Jun-16	3,244	363
Jul-16	2,772	375
Aug-16	3,508	424
Sep-16	3,378	440
Oct-16	3,145	475
Nov-16	3,559	542
Dec-16	3,871	549
Jan-17	4,252	658
Feb-17	4,099	597
Mar-17	2,749	538
Apr-17	3,744	561
May-17	2,885	399
Jun-17	3,283	362
Jul-17	2,724	371
Aug-17	3,532	423
Sep-17	3,398	439
Oct-17	3,157	473
Nov-17	3,594	543
Dec-17	3,930	549
Jan-18	4,249	659
Feb-18	4,032	599
Mar-18	2,726	543
Apr-18	3,758	556
May-18	2,862	397
Jun-18	3,300	363
Jul-18	2,748	367
Aug-18	3,416	419
Sep-18	3,344	436
Oct-18	3,150	471
Nov-18	3,627	547
Dec-18	3,924	554
Jan-19	4,397	665
Feb-19	4,065	602
Mar-19	2,595	532

Regression Analysis **Schedule 2.2-3**
Inuvik
General Service
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.478034611
R Square	0.228517089
Adjusted R Square	0.21521566
Standard Error	503.532953
Observations	60

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4355882.558	4355882.558	17.17988952	0.000112096
Residual	58	14705635.22	253545.4348		
Total	59	19061517.77			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2977.249143	126.9982823	23.44322371	2.84572E-31	2723.034461	3231.463826	2723.034461	3231.463826
X Variable 1	0.609182766	0.146972955	4.144863028	0.000112096	0.314984433	0.903381098	0.314984433	0.903381098

Inuvik
Residential
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.892919541
R Square	0.797305306
Adjusted R Square	0.79381057
Standard Error	43.31001945
Observations	60

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	427944.0836	427944.0836	228.1446395	9.20766E-22
Residual	58	108793.9515	1875.757785		
Total	59	536738.0352			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	351.8331313	10.92341235	32.20908631	1.05021E-38	329.9675458	373.6987168	329.9675458	373.6987168
X Variable 1	0.190942692	0.01264148	15.1044576	9.20766E-22	0.165638021	0.216247362	0.165638021	0.216247362

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
UPC WEATHER NORMALIZATION

Schedule 2.2-4

	Month	Ford Liard				Historical HDD		5-year average HDD
		General Service		Residential				
		Actual UPC	Weather Normalized UPC	Actual UPC	Weather Normalized UPC			
Actual	Apr-11	2,317	2,318	430	431	507.3	April	513.2
	May-11	2,129	2,129	392	392	215.4	May	214.3
	Jun-11	2,349	2,346	396	393	102.7	June	84.5
	Jul-11	3,044	3,042	406	404	42.8	July	31.4
	Aug-11	1,619	1,614	359	355	90.1	August	65.4
	Sep-11	2,265	2,264	389	388	220.9	September	213.0
	Oct-11	2,250	2,255	449	453	471.0	October	498.5
	Nov-11	2,364	2,346	547	532	1,044.4	November	949.1
	Dec-11	2,300	2,351	565	607	893.2	December	1,159.5
	Jan-12	2,300	2,281	565	550	1,200.5	January	1,101.9
	Feb-12	2,221	2,236	477	489	831.0	February	909.2
	Mar-12	2,206	2,190	495	481	904.7	March	819.1
	Apr-12	1,909	1,918	437	444	467.0		
	May-12	2,042	2,043	386	387	207.3		
	Jun-12	1,968	1,967	398	397	85.9		
	Jul-12	2,104	2,106	364	366	16.4		
	Aug-12	1,996	2,001	418	422	39.8		
	Sep-12	1,931	1,941	389	397	161.2		
	Oct-12	1,988	1,961	437	415	638.3		
	Nov-12	2,491	2,466	588	568	1,074.8		
	Dec-12	1,909	1,876	514	487	1,330.8		
	Jan-13	2,703	2,690	628	618	1,168.1		
	Feb-13	2,284	2,291	495	501	876.1		
	Mar-13	1,853	1,836	407	393	906.7		
	Apr-13	2,150	2,120	448	423	672.2		
	May-13	1,808	1,809	377	377	210.7		
	Jun-13	2,257	2,260	363	365	66.8		
	Jul-13	1,796	1,791	327	324	55.4		
	Aug-13	2,125	2,124	384	384	70.2		
	Sep-13	1,902	1,902	386	386	211.8		
	Oct-13	2,015	2,034	415	431	398.8		
	Nov-13	1,633	1,646	472	483	881.2		
	Dec-13	2,541	2,516	571	551	1,286.7		
	Jan-14	2,042	2,064	572	591	986.6		
	Feb-14	1,935	1,908	479	457	1,050.6		
	Mar-14	3,101	3,088	466	455	887.7		
	Apr-14	1,650	1,649	386	385	518.2		
	May-14	2,470	2,460	378	370	266.9		
	Jun-14	3,900	3,899	384	383	91.5		
	Jul-14	2,336	2,339	391	393	15.6		
	Aug-14	2,271	2,271	400	400	62.9		
	Sep-14	2,378	2,372	403	397	247.1		
	Oct-14	2,284	2,278	440	435	524.7		
	Nov-14	2,498	2,490	474	468	988.7		
	Dec-14	3,109	3,110	609	610	1,155.0		
	Jan-15	3,010	3,007	584	582	1,117.9		
	Feb-15	2,019	2,012	475	470	943.2		
	Mar-15	2,753	2,772	541	557	720.9		
	Apr-15	2,485	2,506	428	445	401.5		
	May-15	2,089	2,098	349	355	171.0		
	Jun-15	2,207	2,209	390	391	75.5		
	Jul-15	1,418	1,419	299	300	26.6		
	Aug-15	2,806	2,806	450	450	64.0		
	Sep-15	2,243	2,241	416	414	223.9		
	Oct-15	1,781	1,789	413	419	459.5		
	Nov-15	2,215	2,252	509	539	756.2		
	Dec-15	2,609	2,615	498	503	1,131.7		
	Jan-16	2,593	2,605	542	553	1,036.4		
	Feb-16	2,342	2,354	484	494	845.2		
Forecast	Mar-16	2,561	2,588	465	488	675.3		

Forecast (5-year rolling average)

Schedule 2.2-4

	General Service Weather Normalized Rolling Average UPC	Residential Weather Normalized Rolling Average UPC
Apr-16	2,102	426
May-16	2,108	376
Jun-16	2,536	386
Jul-16	2,139	357
Aug-16	2,163	402
Sep-16	2,144	396
Oct-16	2,064	431
Nov-16	2,240	518
Dec-16	2,494	551
Jan-17	2,530	578
Feb-17	2,160	482
Mar-17	2,495	475
Apr-17	2,059	425
May-17	2,103	373
Jun-17	2,574	385
Jul-17	1,959	348
Aug-17	2,273	411
Sep-17	2,120	398
Oct-17	2,025	426
Nov-17	2,219	515
Dec-17	2,522	540
Jan-18	2,579	584
Feb-18	2,145	481
Mar-18	2,556	474
Apr-18	2,087	421
May-18	2,116	370
Jun-18	2,696	382
Jul-18	1,929	345
Aug-18	2,328	409
Sep-18	2,156	398
Oct-18	2,038	429
Nov-18	2,169	505
Dec-18	2,651	551
Jan-19	2,557	577
Feb-19	2,116	477
Mar-19	2,700	490

Regression Analysis **Schedule 2.2-4**
Ford Liard
General Service
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.190064369
R Square	0.036124464
Adjusted R Square	0.019505921
Standard Error	418.4182641
Observations	60

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	380565.7675	380565.7675	2.173744287	0.145791576
Residual	58	10154282.94	175073.8437		
Total	59	10534848.7			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2159.608057	89.35983159	24.16754843	5.72416E-32	1980.73492	2338.481195	1980.73492	2338.481195
X Variable 1	0.192018028	0.130238018	1.474362332	0.145791576	-0.06868169	0.452717745	-0.06868169	0.452717745

Ford Liard
Residential
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.873314583
R Square	0.762678361
Adjusted R Square	0.758586609
Standard Error	37.09429331
Observations	60

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	256475.7348	256475.7348	186.3940648	9.11468E-20
Residual	58	79807.2226	1375.986596		
Total	59	336282.9574			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	362.1534149	7.922072452	45.71447902	3.43249E-47	346.295664	378.0111658	346.295664	378.0111658
X Variable 1	0.157634142	0.011546072	13.65262117	9.11468E-20	0.134522168	0.180746115	0.134522168	0.180746115

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2016/17

Plant Number	Community Name	Sales Forecast												
		Residential				General Service				Wholesale (MWh)		Industrial (MWh)		Lighting (MWh)
		Number of Customers	Energy Sales Forecast (MW.h)			Billed Demand Forecast (kW)	Energy Sales Forecast (MW.h)			Demand Forecast (kW)	Energy Sales Forecast (MW.h)	Demand Forecast (kW)	Energy Sales Forecast (MW.h)	
			Government	Non-Government	Total		Government	Non-Government	Total					
		A	B	C	D=B+C	E	F	G	H=F+G	I		J		K
	Snare Zone									352,200	163,417	20,880	6,192	
125	Behchoko	520	1,218	2,999	4,217	14,672	1,697	1,391	3,088					62
126	Dettah	91	255	379	634	2,211	252	87	339					8
	Snare Zone Total	**611**	**1,473**	**3,378**	**4,851**	**16,883**	**1,949**	**1,478**	**3,427**	**352,200**	**163,417**	**20,880**	**6,192**	**70**
	Taltson Zone										31,807			
128	Fort Smith	1,047	1,519	9,070	10,588	48,385	7,846	3,873	11,719					232
130	Fort Resolution	221	418	1,175	1,593	6,671	768	340	1,108					28
	Taltson Zone Total	**1,268**	**1,937**	**10,245**	**12,182**	**55,056**	**8,614**	**4,214**	**12,828**	**-**	**31,807**	**-**	**-**	**260**
	Thermal Zone													
123	Wha Ti	136	222	727	949	3,411	538	142	680					13
124	Gameti	87	116	438	553	3,081	378	126	504					6
127	Lutsel K'e	128	288	420	709	3,178	501	181	682					13
131	Fort Simpson	517	503	2,397	2,900	19,828	2,486	1,500	3,987					49
132	Fort Liard	186	195	806	1,001	5,449	494	621	1,114					18
133	Wrigley	60	82	236	318	1,946	274	22	296					9
134	Nahanni Butte	36	6	167	173	1,032	93	91	184					11
135	Jean Marie River	27	9	112	120	1,122	118	22	140					4
136	Inuvik	1,362	1,411	6,414	7,825	78,050	9,151	8,094	17,245					97
137	Norman Wells	404	379	2,821	3,200	26,080	1,859	3,831	5,691					95
138	Tuktoyaktuk	330	1,067	1,038	2,105	7,597	845	698	1,543					26
139	Fort McPherson	298	618	1,007	1,626	7,056	874	632	1,506					25
140	Aklavik	255	764	670	1,433	7,354	775	681	1,455					68
141	Deline	222	565	645	1,210	6,293	611	644	1,255					35
142	Fort Good Hope	211	262	911	1,173	5,979	696	573	1,269					51
143	Paulatuk	105	403	225	628	3,937	502	288	791					11
144	Sachs Harbour	50	169	112	281	2,587	339	202	541					13
145	Tsiigehtchic	69	106	213	319	2,142	219	97	316					8
146	Colville Lake	41	0	224	225	1,402	188	131	320					3
147	Ulukhaktok	153	554	290	844	5,210	663	395	1,058					9
148	Tulit'a	183	473	684	1,157	5,904	646	409	1,056					22
	Thermal Region Total	**4,860**	**8,191**	**20,557**	**28,748**	**198,637**	**22,250**	**19,381**	**41,631**	**-**	**-**	**-**	**-**	**586**
	Total	**6,739**	**11,601**	**34,180**	**45,781**	**270,576**	**32,813**	**25,073**	**57,886**	**352,200**	**195,224**	**20,880**	**6,192**	**916**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2016/17

Plant Number	Community Name	Existing Rates										
		Residential			General Service			Streetlight	Wholesale		Industrial	
		Government, Energy Rates, cents/kW.h	Non-Government, Energy Rates, cents/kW.h	Customer Charge, $/customer/month	Government, Energy Rates, cents/kW.h	Non-Government, Energy Rates, cents/kW.h	Demand Charge, $/kW/month		Demand Charge, $/kW/month	Energy Rates, cents/kW.h	Demand Charge, $/kW/month	Energy Rates, cents/kW.h
		A	B	C	D	E	F	G	H	I	J	K
	Snare Zone								8.10	19.21	11.76	14.99
125	Behchoko	32.06	31.10	18.00	39.47	38.29	8.00	92.04				
126	Dettah	35.76	31.10	18.00	44.32	38.29	8.00	78.69				
	Snare Zone Total											
	Taltson Zone									10.83		
128	Fort Smith	21.00	21.00	18.00	16.53	16.53	8.00	31.05				
130	Fort Resolution	26.63	21.00	18.00	23.14	16.53	8.00	43.72				
	Taltson Zone Total											
	Thermal Zone											
123	Wha Ti	108.55	60.83	18.00	100.76	51.60	8.00	178.26				
124	Gameti	166.60	60.83	18.00	191.48	51.60	8.00	214.15				
127	Lutsel K'e	100.80	60.83	18.00	93.74	51.60	8.00	160.31				
131	Fort Simpson	94.26	60.83	18.00	82.58	51.60	8.00	105.74				
132	Fort Liard	100.19	60.83	18.00	90.32	51.60	8.00	154.60				
133	Wrigley	177.03	60.83	18.00	189.31	51.60	8.00	246.53				
134	Nahanni Butte	213.58	60.83	18.00	275.51	51.60	8.00	327.79				
135	Jean Marie River	190.86	60.83	18.00	257.54	51.60	8.00	344.03				
136	Inuvik	77.46	60.83	18.00	68.90	51.60	8.00	90.86				
137	Norman Wells	57.39	47.54	18.00	52.14	43.20	8.00	76.65				
138	Tuktoyaktuk	90.87	60.83	18.00	80.70	51.60	8.00	123.30				
139	Fort McPherson	104.72	60.83	18.00	95.80	51.60	8.00	116.99				
140	Aklavik	83.22	60.83	18.00	79.52	51.60	8.00	112.09				
141	Deline	106.79	60.83	18.00	100.76	51.60	8.00	91.58				
142	Fort Good Hope	92.94	60.83	18.00	81.40	51.60	8.00	108.37				
143	Paulatuk	157.77	60.83	18.00	149.08	51.60	8.00	174.71				
144	Sachs Harbour	195.25	60.83	18.00	183.01	51.60	8.00	209.33				
145	Tsiigehtchic	144.67	60.83	18.00	128.15	51.60	8.00	183.38				
146	Colville Lake	295.55	60.83	18.00	257.04	51.60	8.00	735.56				
147	Ulukhaktok	90.81	60.83	18.00	82.20	51.60	8.00	119.95				
148	Tulit'a	114.89	60.83	18.00	110.97	51.60	8.00	132.46				

'.h based on total revenue to take into account new LED rates.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2016/17

Plant Number	Community Name	Revenues at Existing Rates, $000									
		Residential			General Service			Streetlight	Wholesale Demand and Energy	Industrial Demand and Energy	Total Revenues
		Energy	Customer Charge	Total	Energy	Demand Charge	Total				
		A	B	C=A+B	D	E	F=D+E	G	H	I	J=C+F+G+H+I
	Snare Zone								34,245	1,174	35,419
125	Behchoko	1,323	112	1,436	1,202	117	1,320	57			2,812
126	Dettah	209	20	229	145	18	163	7			398
	Snare Zone Total	**1,532**	**132**	**1,664**	**1,347**	**135**	**1,482**	**63**	**34,245**	**1,174**	**38,629**
	Taltson Zone								3,409		3,409
128	Fort Smith	2,224	226	2,450	1,937	387	2,324	72			4,846
130	Fort Resolution	358	48	406	234	53	287	12			705
	Taltson Zone Total	**2,582**	**274**	**2,856**	**2,171**	**440**	**2,612**	**84**	**3,409**	**-**	**8,961**
	Thermal Zone										
123	Wha Ti	683	29	713	615	27	642	23			1,378
124	Gameti	459	19	478	788	25	813	13			1,304
127	Lutsel K'e	547	28	574	563	25	589	21			1,184
131	Fort Simpson	1,932	112	2,043	2,827	159	2,986	52			5,081
132	Fort Liard	685	40	725	766	44	810	27			1,562
133	Wrigley	289	13	302	531	16	546	23			871
134	Nahanni Butte	114	8	122	303	8	311	37			470
135	Jean Marie River	84	6	90	315	9	324	14			428
136	Inuvik	4,995	294	5,289	10,481	624	11,106	88			16,483
137	Norman Wells	1,559	87	1,646	2,625	209	2,833	73			4,552
138	Tuktoyaktuk	1,601	71	1,672	1,042	61	1,102	32			2,807
139	Fort McPherson	1,260	64	1,324	1,164	56	1,220	29			2,574
140	Aklavik	1,043	55	1,098	967	59	1,026	76			2,200
141	Deline	996	48	1,043	948	50	998	32			2,073
142	Fort Good Hope	798	46	843	862	48	910	55			1,809
143	Paulatuk	772	23	795	898	31	929	19			1,743
144	Sachs Harbour	398	11	409	725	21	746	26			1,181
145	Tsiigehtchic	283	15	298	331	17	348	14			660
146	Colville Lake	137	9	146	552	11	563	24			733
147	Ulukhaktok	679	33	712	749	42	791	11			1,514
148	Tulit'a	960	40	999	928	47	976	29			2,004
	Thermal Region Total	**20,273**	**1,050**	**21,323**	**28,980**	**1,589**	**30,569**	**719**	**-**	**-**	**52,611**
	Total	**24,387**	**1,456**	**25,843**	**32,498**	**2,165**	**34,663**	**867**	**37,654**	**1,174**	**100,201**

1. Taltson Wholesale includes interruptible allocations which have a rate of 5.42 cents/kWh.
2. Thermal Zone Non-Government Totals includes Norman Wells subtotals.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2017/18

Plant Number	Community Name	Sales Forecast												
		Residential				General Service				Wholesale (MWh)		Industrial (MWh)		Lighting (MWh)
		Number of Customers	Energy Sales Forecast (MW.h)			Billed Demand Forecast (kW)	Energy Sales Forecast (MW.h)			Demand Forecast (kW)	Energy Sales Forecast (MW.h)	Demand Forecast (kW)	Energy Sales Forecast (MW.h)	
			Government	Non-Government	Total		Government	Non-Government	Total					
		A	B	C	D=B+C	E	F	G	H=F+G	I		J		K
	Snare Zone									352,200	163,417	20,880	6,192	
125	Behchoko	520	1,213	2,988	4,201	14,672	1,717	1,408	3,125					62
126	Dettah	91	256	380	635	2,211	245	84	329					8
	Snare Zone Total	**611**	**1,469**	**3,367**	**4,836**	**16,883**	**1,962**	**1,492**	**3,454**	**352,200**	**163,417**	**20,880**	**6,192**	**70**
	Taltson Zone										31,801			
128	Fort Smith	1,047	1,528	9,123	10,651	48,385	7,835	3,868	11,703					232
130	Fort Resolution	221	421	1,183	1,604	6,671	771	341	1,112					28
	Taltson Zone Total	**1,268**	**1,949**	**10,306**	**12,255**	**55,056**	**8,606**	**4,209**	**12,815**	**-**	**31,801**	**-**	**-**	**260**
	Thermal Zone													
123	Wha Ti	136	224	731	955	3,411	529	140	669					13
124	Gameti	87	117	442	559	3,081	380	127	507					6
127	Lutsel K'e	128	292	426	717	3,178	497	179	677					13
131	Fort Simpson	517	504	2,405	2,910	19,828	2,561	1,546	4,107					49
132	Fort Liard	186	194	803	997	5,449	493	620	1,113					18
133	Wrigley	60	81	233	314	1,946	282	22	304					9
134	Nahanni Butte	36	6	167	173	1,032	90	88	178					11
135	Jean Marie River	27	9	114	123	1,122	121	23	144					4
136	Inuvik	1,362	1,410	6,412	7,823	78,050	9,173	8,114	17,288					97
137	Norman Wells	404	379	2,820	3,199	26,080	1,862	3,837	5,699					95
138	Tuktoyaktuk	330	1,066	1,036	2,102	7,597	848	701	1,549					26
139	Fort McPherson	298	611	997	1,608	7,056	874	631	1,505					25
140	Aklavik	255	766	671	1,437	7,354	771	678	1,449					68
141	Deline	222	565	645	1,210	6,293	620	654	1,274					35
142	Fort Good Hope	211	262	912	1,174	5,979	707	582	1,289					51
143	Paulatuk	105	399	223	622	3,937	500	287	787					11
144	Sachs Harbour	50	171	114	285	2,587	339	202	540					13
145	Tsiigehtchic	69	106	213	319	2,142	219	97	316					8
146	Colville Lake	41	0	231	231	1,402	186	130	316					3
147	Ulukhaktok	153	555	291	845	5,210	671	399	1,070					9
148	Tulit'a	183	478	690	1,168	5,904	653	413	1,066					22
	Thermal Region Total	**4,860**	**8,195**	**20,578**	**28,773**	**198,637**	**22,377**	**19,470**	**41,847**	**-**	**-**	**-**	**-**	**586**
	Total	**6,739**	**11,613**	**34,251**	**45,864**	**270,576**	**32,944**	**25,172**	**58,116**	**352,200**	**195,218**	**20,880**	**6,192**	**916**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2017/18

Plant Number	Community Name	Existing Rates										
		Residential			General Service			Streetlight	Wholesale		Industrial	
		Government, Energy Rates, cents/kW.h	Non-Government, Energy Rates, cents/kW.h	Customer Charge, $/customer/month	Government, Energy Rates, cents/kW.h	Non-Government, Energy Rates, cents/kW.h	Demand Charge, $/kW/month		Demand Charge, $/kW/month	Energy Rates, cents/kW.h	Demand Charge, $/kW/month	Energy Rates, cents/kW.h
		A	B	C	D	E	F	G	H	I	J	K
	Snare Zone								8.10	19.21	11.76	14.99
125	Behchoko	32.06	31.10	18.00	39.47	38.29	8.00	92.04				
126	Dettah	35.76	31.10	18.00	44.32	38.29	8.00	78.69				
	Snare Zone Total											
	Taltson Zone									10.83		
128	Fort Smith	21.00	21.00	18.00	16.53	16.53	8.00	31.05				
130	Fort Resolution	26.63	21.00	18.00	23.14	16.53	8.00	43.72				
	Taltson Zone Total											
	Thermal Zone											
123	Wha Ti	108.55	60.83	18.00	100.76	51.60	8.00	178.26				
124	Gameti	166.60	60.83	18.00	191.48	51.60	8.00	214.15				
127	Lutsel K'e	100.80	60.83	18.00	93.74	51.60	8.00	160.31				
131	Fort Simpson	94.26	60.83	18.00	82.58	51.60	8.00	105.74				
132	Fort Liard	100.19	60.83	18.00	90.32	51.60	8.00	154.60				
133	Wrigley	177.03	60.83	18.00	189.31	51.60	8.00	246.53				
134	Nahanni Butte	213.58	60.83	18.00	275.51	51.60	8.00	327.79				
135	Jean Marie River	190.86	60.83	18.00	257.54	51.60	8.00	344.03				
136	Inuvik	77.46	60.83	18.00	68.90	51.60	8.00	90.86				
137	Norman Wells	57.39	47.54	18.00	52.14	43.20	8.00	76.65				
138	Tuktoyaktuk	90.87	60.83	18.00	80.70	51.60	8.00	123.30				
139	Fort McPherson	104.72	60.83	18.00	95.80	51.60	8.00	116.99				
140	Aklavik	83.22	60.83	18.00	79.52	51.60	8.00	112.09				
141	Deline	106.79	60.83	18.00	100.76	51.60	8.00	91.58				
142	Fort Good Hope	92.94	60.83	18.00	81.40	51.60	8.00	108.37				
143	Paulatuk	157.77	60.83	18.00	149.08	51.60	8.00	174.71				
144	Sachs Harbour	195.25	60.83	18.00	183.01	51.60	8.00	209.33				
145	Tsiigehtchic	144.67	60.83	18.00	128.15	51.60	8.00	183.38				
146	Colville Lake	295.55	60.83	18.00	257.04	51.60	8.00	735.56				
147	Ulukhaktok	90.81	60.83	18.00	82.20	51.60	8.00	119.95				
148	Tulit'a	114.89	60.83	18.00	110.97	51.60	8.00	132.46				

'.h based on total revenue to take into account new LED rates.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2017/18

Plant Number	Community Name	Revenues at Existing Rates, $000									
		Residential			General Service			Streetlight	Wholesale Demand and Energy	Industrial Demand and Energy	Total Revenues
		Energy	Customer Charge	Total	Energy	Demand Charge	Total				
		A	B	C=A+B	D	E	F=D+E	G	H	I	J=C+F+G+H+I
	Snare Zone								34,245	1,174	35,419
125	Behchoko	1,318	112	1,430	1,217	117	1,334	57			2,821
126	Dettah	209	20	229	141	18	158	7			394
	Snare Zone Total	**1,527**	**132**	**1,659**	**1,357**	**135**	**1,493**	**63**	**34,245**	**1,174**	**38,634**
	Taltson Zone								3,408		3,408
128	Fort Smith	2,237	226	2,463	1,934	387	2,322	72			4,856
130	Fort Resolution	361	48	408	235	53	288	12			709
	Taltson Zone Total	**2,597**	**274**	**2,871**	**2,169**	**440**	**2,610**	**84**	**3,408**	**-**	**8,973**
	Thermal Zone										
123	Wha Ti	687	29	717	606	27	633	23			1,372
124	Gameti	464	19	482	794	25	818	13			1,314
127	Lutsel K'e	553	28	581	559	25	584	21			1,186
131	Fort Simpson	1,939	112	2,050	2,913	159	3,071	52			5,173
132	Fort Liard	683	40	723	765	44	808	27			1,559
133	Wrigley	286	13	299	545	16	561	23			882
134	Nahanni Butte	115	8	123	293	8	301	37			460
135	Jean Marie River	86	6	92	324	9	333	14			439
136	Inuvik	4,993	294	5,287	10,507	624	11,132	88			16,507
137	Norman Wells	1,558	87	1,645	2,628	209	2,837	73			4,555
138	Tuktoyaktuk	1,599	71	1,670	1,046	61	1,107	32			2,809
139	Fort McPherson	1,247	64	1,311	1,163	56	1,219	29			2,559
140	Aklavik	1,046	55	1,101	963	59	1,022	76			2,199
141	Deline	996	48	1,044	962	50	1,013	32			2,088
142	Fort Good Hope	798	46	844	876	48	924	55			1,823
143	Paulatuk	766	23	788	894	31	925	19			1,733
144	Sachs Harbour	404	11	415	724	21	744	26			1,185
145	Tsiigehtchic	283	15	298	331	17	348	14			660
146	Colville Lake	141	9	150	546	11	557	24			731
147	Ulukhaktok	680	33	713	758	42	799	11			1,523
148	Tulit'a	969	40	1,008	938	47	985	29			2,023
	Thermal Region Total	**20,291**	**1,050**	**21,341**	**29,132**	**1,589**	**30,721**	**719**	**-**	**-**	**52,781**
	Total	**24,416**	**1,456**	**25,872**	**32,659**	**2,165**	**34,823**	**867**	**37,654**	**1,174**	**100,389**

1. Taltson Wholesale includes interruptible allocations which have a rate of 5.42 cents/kWh.
2. Thermal Zone Non-Government Totals includes Norman Wells subtotals.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2018/19

Plant Number	Community Name	Sales Forecast												
		Residential				General Service				Wholesale (MWh)		Industrial (MWh)		Lighting (MWh)
		Number of Customers	Energy Sales Forecast (MW.h)			Billed Demand Forecast (kW)	Energy Sales Forecast (MW.h)			Demand Forecast (kW)	Energy Sales Forecast (MW.h)	Demand Forecast (kW)	Energy Sales Forecast (MW.h)	
			Government	Non-Government	Total		Government	Non-Government	Total					
		A	B	C	D=B+C	E	F	G	H=F+G	I		J		K
	Snare Zone									352,200	163,417	20,880	6,192	
125	Behchoko	520	1,203	2,964	4,167	14,672	1,739	1,425	3,164					62
126	Dettah	91	249	370	618	2,211	247	85	332					8
	Snare Zone Total	**611**	**1,452**	**3,333**	**4,785**	**16,883**	**1,985**	**1,510**	**3,496**	**352,200**	**163,417**	**20,880**	**6,192**	**70**
	Taltson Zone										31,810			
128	Fort Smith	1,047	1,532	9,147	10,679	48,385	7,824	3,863	11,687					232
130	Fort Resolution	221	423	1,188	1,611	6,671	777	344	1,121					28
	Taltson Zone Total	**1,268**	**1,955**	**10,335**	**12,290**	**55,056**	**8,601**	**4,207**	**12,808**	**-**	**31,810**	**-**	**-**	**260**
	Thermal Zone													
123	Wha Ti	136	224	731	955	3,411	524	139	663					13
124	Gameti	87	116	438	554	3,081	381	127	508					6
127	Lutsel K'e	128	296	432	728	3,178	493	178	671					13
131	Fort Simpson	517	505	2,406	2,911	19,828	2,550	1,539	4,088					49
132	Fort Liard	186	194	802	996	5,449	500	629	1,129					18
133	Wrigley	60	80	230	311	1,946	291	23	314					9
134	Nahanni Butte	36	6	168	174	1,032	91	89	180					11
135	Jean Marie River	27	9	115	124	1,122	123	23	146					4
136	Inuvik	1,362	1,408	6,399	7,807	78,050	9,158	8,101	17,259					97
137	Norman Wells	404	379	2,821	3,200	26,080	1,861	3,834	5,695					95
138	Tuktoyaktuk	330	1,066	1,036	2,103	7,597	859	709	1,568					26
139	Fort McPherson	298	605	986	1,590	7,056	857	619	1,476					25
140	Aklavik	255	768	673	1,441	7,354	775	681	1,456					68
141	Deline	222	565	646	1,211	6,293	625	659	1,284					35
142	Fort Good Hope	211	261	908	1,169	5,979	722	594	1,316					51
143	Paulatuk	105	399	223	621	3,937	495	284	779					11
144	Sachs Harbour	50	175	116	291	2,587	333	198	532					13
145	Tsiigehtchic	69	106	213	319	2,142	220	97	317					8
146	Colville Lake	41	0	234	234	1,402	186	130	316					3
147	Ulukhaktok	153	559	293	851	5,210	672	400	1,072					9
148	Tulit'a	183	478	691	1,169	5,904	658	417	1,075					22
	Thermal Region Total	**4,860**	**8,197**	**20,562**	**28,759**	**198,637**	**22,373**	**19,471**	**41,844**	**-**	**-**	**-**	**-**	**586**
	Total	**6,739**	**11,604**	**34,230**	**45,834**	**270,576**	**32,959**	**25,188**	**58,148**	**352,200**	**195,227**	**20,880**	**6,192**	**916**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2018/19

Plant Number	Community Name	Existing Rates										
		Residential			General Service			Streetlight	Wholesale		Industrial	
		Government, Energy Rates, cents/kW.h	Non-Government, Energy Rates, cents/kW.h	Customer Charge, $/customer/month	Government, Energy Rates, cents/kW.h	Non-Government, Energy Rates, cents/kW.h	Demand Charge, $/kW/month		Demand Charge, $/kW/month	Energy Rates, cents/kW.h	Demand Charge, $/kW/month	Energy Rates, cents/kW.h
		A	B	C	D	E	F	G	H	I	J	K
	Snare Zone								8.10	19.21	11.76	14.99
125	Behchoko	32.06	31.10	18.00	39.47	38.29	8.00	92.04				
126	Dettah	35.76	31.10	18.00	44.32	38.29	8.00	78.69				
	Snare Zone Total											
	Taltson Zone									10.83		
128	Fort Smith	21.00	21.00	18.00	16.53	16.53	8.00	31.05				
130	Fort Resolution	26.63	21.00	18.00	23.14	16.53	8.00	43.72				
	Taltson Zone Total											
	Thermal Zone											
123	Wha Ti	108.55	60.83	18.00	100.76	51.60	8.00	178.26				
124	Gameti	166.60	60.83	18.00	191.48	51.60	8.00	214.15				
127	Lutsel K'e	100.80	60.83	18.00	93.74	51.60	8.00	160.31				
131	Fort Simpson	94.26	60.83	18.00	82.58	51.60	8.00	105.74				
132	Fort Liard	100.19	60.83	18.00	90.32	51.60	8.00	154.60				
133	Wrigley	177.03	60.83	18.00	189.31	51.60	8.00	246.53				
134	Nahanni Butte	213.58	60.83	18.00	275.51	51.60	8.00	327.79				
135	Jean Marie River	190.86	60.83	18.00	257.54	51.60	8.00	344.03				
136	Inuvik	77.46	60.83	18.00	68.90	51.60	8.00	90.86				
137	Norman Wells	57.39	47.54	18.00	52.14	43.20	8.00	76.65				
138	Tuktoyaktuk	90.87	60.83	18.00	80.70	51.60	8.00	123.30				
139	Fort McPherson	104.72	60.83	18.00	95.80	51.60	8.00	116.99				
140	Aklavik	83.22	60.83	18.00	79.52	51.60	8.00	112.09				
141	Deline	106.79	60.83	18.00	100.76	51.60	8.00	91.58				
142	Fort Good Hope	92.94	60.83	18.00	81.40	51.60	8.00	108.37				
143	Paulatuk	157.77	60.83	18.00	149.08	51.60	8.00	174.71				
144	Sachs Harbour	195.25	60.83	18.00	183.01	51.60	8.00	209.33				
145	Tsiigehtchic	144.67	60.83	18.00	128.15	51.60	8.00	183.38				
146	Colville Lake	295.55	60.83	18.00	257.04	51.60	8.00	735.56				
147	Ulukhaktok	90.81	60.83	18.00	82.20	51.60	8.00	119.95				
148	Tulit'a	114.89	60.83	18.00	110.97	51.60	8.00	132.46				

'.h based on total revenue to take into account new LED rates.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EXISTING RATE REVENUES - 2018/19

Plant Number	Community Name	Revenues at Existing Rates, $000									
		Residential			General Service			Streetlight	Wholesale Demand and Energy	Industrial Demand and Energy	Total Revenues
		Energy	Customer Charge	Total	Energy	Demand Charge	Total				
		A	B	C=A+B	D	E	F=D+E	G	H	I	J=C+F+G+H+I
	Snare Zone								34,245	1,174	35,419
125	Behchoko	1,307	112	1,420	1,232	117	1,349	57			2,826
126	Dettah	204	20	224	142	18	160	7			390
	Snare Zone Total	**1,511**	**132**	**1,643**	**1,374**	**135**	**1,509**	**63**	**34,245**	**1,174**	**38,635**
	Taltson Zone								3,409		3,409
128	Fort Smith	2,242	226	2,469	1,932	387	2,319	72			4,860
130	Fort Resolution	362	48	410	237	53	290	12			712
	Taltson Zone Total	**2,605**	**274**	**2,879**	**2,169**	**440**	**2,609**	**84**	**3,409**	**-**	**8,981**
	Thermal Zone										
123	Wha Ti	687	29	717	599	27	627	23			1,366
124	Gameti	460	19	478	795	25	820	13			1,311
127	Lutsel K'e	561	28	589	554	25	580	21			1,189
131	Fort Simpson	1,940	112	2,051	2,900	159	3,058	52			5,161
132	Fort Liard	682	40	722	776	44	820	27			1,569
133	Wrigley	282	13	295	563	16	578	23			896
134	Nahanni Butte	115	8	123	296	8	304	37			464
135	Jean Marie River	87	6	93	328	9	337	14			443
136	Inuvik	4,983	294	5,277	10,490	624	11,114	88			16,480
137	Norman Wells	1,558	87	1,646	2,626	209	2,835	73			4,554
138	Tuktoyaktuk	1,599	71	1,671	1,059	61	1,120	32			2,822
139	Fort McPherson	1,233	64	1,297	1,140	56	1,197	29			2,523
140	Aklavik	1,049	55	1,104	968	59	1,027	76			2,207
141	Deline	996	48	1,044	970	50	1,020	32			2,096
142	Fort Good Hope	795	46	841	894	48	942	55			1,838
143	Paulatuk	764	23	787	884	31	916	19			1,722
144	Sachs Harbour	412	11	423	712	21	733	26			1,182
145	Tsiigehtchic	283	15	298	332	17	349	14			661
146	Colville Lake	143	9	151	546	11	558	24			733
147	Ulukhaktok	685	33	718	759	42	800	11			1,529
148	Tulit'a	970	40	1,009	945	47	992	29			2,031
	Thermal Region Total	**20,285**	**1,050**	**21,335**	**29,137**	**1,589**	**30,726**	**719**	**-**	**-**	**52,780**
	Total	**24,401**	**1,456**	**25,856**	**32,680**	**2,165**	**34,844**	**867**	**37,655**	**1,174**	**100,396**

1. Taltson Wholesale includes interruptible allocations which have a rate of 5.42 cents/kWh.
2. Thermal Zone Non-Government Totals includes Norman Wells subtotals.

CHAPTER 3

TOTAL REVENUE REQUIREMENT

3.0 TOTAL REVENUE REQUIREMENT

NTPC's 2016/19 Revenue Requirement reflects the forecast cost of providing service in the Test Years, including a return on equity (in the two hydro zones) or an interest coverage provision (in the thermal zone). The Revenue Requirement is recovered by way of rates charged for electrical service to NTPC's retail, wholesale and industrial customers as well as non-electrical revenues (such as revenues from pole rentals). Section 3.1 reviews changes to the Revenue Requirement since the 2013/14 Test Year and identifies major cost drivers. Section 3.2 compares Revenue Requirement by zone and identifies major cost drivers.

Further details on the calculation of NTPC's Revenue Requirement for the Test Years are provided in the following chapters:

- Chapter 4: Fuel, Purchased Power and Generation
- Chapter 5: Operations and Maintenance Expense
- Chapter 6: Amortization Expense
- Chapter 7: Return on Rate Base

- Chapter 11 Rate Base

3.1 REVENUE REQUIREMENT CHANGES SINCE THE 2012/14 GRA

The Revenue Requirement forecast for 2016/17, 2017/18 and 2018/19 is set out in Table 3.1 below and Schedule 3.0.

Table 3.1
Revenue Requirement – 2013/14 Compared to 2016/17 – 2018/19 Test Years
($000s)

		Test Year		
	2013/14	2016/17	2017/18	2018/19
Revenue Requirement	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Operating and Maintenance Costs	39,023	42,185	43,372	44,023
Production Fuel and Purchased Power	27,630	23,400	23,912	24,360
Fixed Asset Amortization	14,470	16,408	17,434	18,293
Deferred Charges Amortization	5,348	7,865	7,977	7,809
Return on Rate Base	19,142	20,214	20,516	20,340
Revenue Requirement	105,613	110,072	113,212	114,824

The 2016/17 Revenue Requirement has increased by $4.46 million from the 2013/14 Test Year which equates to 4.2% or 1.4% per year on average. Changes in Revenue Requirement include the following items:

Aging Infrastructure and Increased Asset Management and Preventative Maintenance:

Many of NTPC's generating facilities were constructed in the 1970's or 1980's and in some cases, such as the Corporation's hydro plants, even earlier. NTPC has worked to use existing assets or upgrade existing plants to meet current service requirements

where possible. However, the inevitable aging of the basic infrastructure will continue to require NTPC's investment in a capital replacement program to maintain reliable service for customers.

- Non-Production Fuel Operating and Maintenance

  As discussed in Chapter 5, the Corporation has an increased focus on preventative maintenance and asset management. Accordingly the Corporation has added 2 Full Time Equivalent (FTE) positions and refocused four existing positions for preventative maintenance. The Corporation has also increased consumption of consumables (lube and oil) due to the increased preventative maintenance program, increased costs for hydro maintenance as Original Equipment Manufacture experts are used for preventative maintenance on older equipment, increased costs for boiler inspections and building maintenance costs.

- Fixed Asset Amortization

  The Corporation completed a new amortization study with new rates but the largest cost driver is gross plant additions to replace the aging infrastructure. Please refer to Table 6.2 in Chapter 6 for the change in fixed asset amortization.

- Deferred Charges Amortization

  The Corporation is forecasting a need to increase the overhaul deferral account amortization from $2.936 million to $3.935 million per year. The costs for the annual shutdown of the Taltson hydro plant have increased as a result of the

increased scope of work related to the age of the equipment. In addition, the larger diesel engines in Fort Smith and Inuvik have scheduled major overhauls in 2016 and 2017. The Corporation also completed a Power System Plan and asset condition assessments that are included in deferred expenses. The asset condition assessments in conjunction with the Computer Management and Maintenance System and the Power System Plan were used to redevelop preventative maintenance programs and capital planning to replace the aging infrastructure.

- Return on Rate Base

  Return on Rate Base increased by $1 million or 5% due to increased investment in gross plant to replace aging infrastructure. The impacts of increased capital investment are reduced by the average rate of return decreasing from 6.43% to 6.34%.

Increased Regulation

Responding to changes in regulation requires both human and financial resources and the 2016/19 GRA incorporates the resources needed to meet these obligations under the new regulatory regimes.

- Non-Production Fuel Operating and Maintenance

  As discussed in Chapter 5, the Corporation has also added 3 FTE's due to increased regulatory compliance and reporting, a Management Accountant for

regulatory and Public Sector Accounting Standards, an Environmental Licensing Specialist and a Construction Health and Safety Coordinator.

- Deferred Charges Amortization

The Corporation is forecasting a need to increase the water licence deferral account amortization from $0.825 million to $1.611 million per year. The increased annual costs relate to increased required environmental monitoring at Bluefish dam and Taltson dam, increased costs related to dam inspections as a result of dam safety reviews, required flood surveys and increased costs relating to annual dam testing and inspections.

Inflation Compared to Lack of Sales Growth and Production Fuel Costs

Excluding salary and wages, non-production fuel operating and maintenance expenses have increased $1.8 million from the 2012/14 GRA due to inflation using a 2% inflation rate over the 3 year period. Although revenue at existing rates is not included in the Revenue Requirement calculation, total sales have decreased by 1.5% per year compounding the impact of inflation on the Corporation's operations especially in the hydro zones where there is little or no fuel savings associated with the decreased sales.

Production Fuel costs have decreased $4.2 million or 15% over the three years. On average, diesel fuel prices are forecast to be 10% lower in 2016/17 compared to 2013/14. Purchased power prices are forecast to be approximately 40% lower and natural gas prices are forecast to be 5% lower.

Strategic Direction and Initiatives

As discussed in Chapter 1 and excluding items above (such as redeveloped preventative maintenance programs and asset replacement) the Corporation has a number of strategic initiatives that have an impact on Revenue Requirement.

- Non-Production Fuel Operating and Maintenance

  Strategic initiatives such as meeting customer commitments, developing and retaining a highly skilled workforce, COR certification, Health and Safety Management System, Lone Worker system, improved training programs, new Careers website, continued strategic focus on Contractor safety, leadership employee development and the development of a corporate risk registry has increased operating and maintenance costs. As discussed in Chapter 5, the Corporation has added 3.5 FTE's in the Customer Service division and refocused existing position to meet customer commitments. The Corporation has also created 4 FTE's for developmental positions for succession planning and to mitigate the risks associated with loss of knowledge due to an aging workforce.

3.2 REVENUE REQUIREMENT CHANGES SINCE THE 2012/14 GRA BY ZONE

The Revenue Requirement forecast for 2016/17 compared to 2013/14 Test Year for the Snare zone is set out in Table 3.2.

Table 3.2
Revenue Requirement – 2013/14 Compared to 2016/17 – Snare Zone ($000s)

Revenue Requirement	2013/14 Forecast	2016/17 Forecast	Change
Zone Specific Costs			
Operating and Maintenance Costs	7,668	8,067	399
Production Fuel and Purchased Power	338	932	594
Fixed Asset Amortization	5,836	6,507	672
Deferred Charges Amortization	581	1,416	835
Return on Rate Base	11,267	11,166	(101)
Total Zone Specific Revenue Requirement	25,689	28,088	2,399
Common Cost Allocation by Zone			
Operating and Maintenance Costs	7,945	8,825	880
Corporate/Regional Amortization	929	1,268	339
Deferred Charges Amortization	924	1,349	425
Return on Ratebase	1,019	1,281	262
Total Common Cost Revenue Requirement	10,817	12,723	1,906
Total Revenue Requirement	**36,506**	**40,810**	**4,304**

The Corporation has reclassified operations and maintenance expenses between plant and regional/corporate costs. This is one reason for the $0.880 million increase in common operating and maintenance costs and the marginal increase to plant operating and maintenance costs. Please refer to Chapter 5 for further explanation of changes in operating and maintenance expenses. Production fuel costs have increased due to the increased diesel generation in Yellowknife. Fixed asset amortization and return on Rate Base for plant and common costs increased as a result of investment in gross plant and the new amortization study. Deferred charges amortization has increased due to costs incurred to maintain the water licences at Bluefish and Snare. The higher annual costs relate to increased environmental monitoring at Bluefish dam and increased costs

related to dam inspections as a result of dam safety reviews, required flood surveys and increased costs relating to annual dam testing and inspections. Common cost deferred amortization expense has increased due to increased regulatory reporting charged to the regulatory deferral account and the employee future benefits deferral account increasing because of a new actuarial study and higher than forecast employee turnover.

The Revenue Requirement forecast for 2016/17 compared to the 2013/14 Test Year for the Taltson zone is set out in Table 3.3.

Table 3.3

Revenue Requirement – 2013/14 Compared to 2016/17 – Taltson Zone ($000s)

Revenue Requirement	2013/14 Forecast	Test Year 2016/17 Forecast	Change
Zone Specific Costs			
Operating and Maintenance Costs	3,381	3,248	(133)
Production Fuel and Purchased Power	289	276	(13)
Fixed Asset Amortization	1,138	1,197	59
Deferred Charges Amortization	713	1,300	587
Return on Rate Base	1,659	1,870	211
Total Zone Specific Revenue Requirement	7,180	7,891	711
Common Cost Allocation by Zone			
Operating and Maintenance Costs	2,673	3,481	808
Corporate/Regional Amortization	294	410	116
Deferred Charges Amortization	286	433	147
Return on Ratebase	332	412	80
Total Common Cost Revenue Requirement	3,585	4,736	1,151
Total Revenue Requirement	**10,765**	**12,627**	**1,862**

The Corporation has reclassified operations and maintenance expenses between plant and regional/corporate costs. This is one reason for the $0.808 million increase in

common operating and maintenance costs and the marginal increase to plant operating and maintenance costs. Please refer to Chapter 5 for further explanation to changes in operations and maintenance expenses. Fixed asset amortization and return on Rate Base for plant and common costs increased due to investment in gross plant and the new amortization study. Deferred charges amortization has increased as a result of costs incurred to maintain the water licenses at Taltson. The increased annual costs relate to increased required environmental monitoring at Taltson and increased costs related to dam inspections, annual dam testing and inspections as a result of dam safety reviews. Costs for overhauls in the Taltson zone have increased. Costs for the annual shutdown of the Taltson hydro plant have increased as a result of inflation, and the increased scope of work related to the age of the equipment. In addition, the larger diesel engines in Fort Smith have received scheduled major overhauls in 2016 and 2017. Common cost deferred amortization expense has increased due to increased regulatory reporting charged to the regulatory deferral account and the employee future benefits deferral account increasing based on a new actuarial study and higher than forecast employee turnover.

The Revenue Requirement forecast for 2016/17 compared to 2013/14 Test Year for the Thermal zone is set out in Table 3.4.

Table 3.4

Revenue Requirement – 2013/14 Compared to 2016/17 – Thermal Zone ($000s)

Revenue Requirement	2013/14 Forecast	Test Year 2016/17 Forecast	Change
Zone Specific Costs			
Operating and Maintenance Costs	13,273	12,554	(719)
Production Fuel and Purchased Power	27,003	22,192	(4,811)
Fixed Asset Amortization	5,869	6,531	662
Deferred Charges Amortization	2,467	2,830	363
Return on Rate Base	4,381	5,005	624
Total Zone Specific Revenue Requirement	52,993	49,112	(3,881)
Common Cost Allocation by Zone			
Operating and Maintenance Costs	4,083	6,010	1,927
Corporate/Regional Amortization	404	495	91
Deferred Charges Amortization	377	538	161
Return on Ratebase	484	481	(3)
Total Common Cost Revenue Requirement	5,348	7,524	2,176
Total Revenue Requirement	**58,341**	**56,636**	**(1,706)**

The Corporation has reclassified operations and maintenance expenses between plant and regional/corporate costs. This is one reason for the $1.927 million increase in common operating and maintenance costs and the reduction to plant operating and maintenance costs. Please refer to Chapter 5 for further explanation to changes in operating and maintenance expenses. Production fuel and purchased power prices are lower due to lower fuel prices. Fixed asset amortization and return on Rate Base for plant and common costs increased due to investment in gross plant and the new amortization study. Deferred charges amortization has increased as a result of costs incurred for engine overhauls. In particular for 2016/17 overhauls in Inuvik are higher as the larger units are due for major overhauls. Common cost deferred amortization

expense has increased due to increased regulatory reporting charged to the regulatory deferral account and the employee future benefits deferral account increasing based on a new actuarial study and higher than forecast employee turnover.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
REVENUE REQUIREMENT
(in thousands of dollars)

Line No.	Cross Ref.		2013/14 Forecast	2013/14 Actuals	2014/15 Actuals	2015/16 Forecast	Test Year 2016/17 Forecast	Test Year 2017/18 Forecast	Test Year 2018/19 Forecast
1		**Non-Production Fuel Operation & Maintenance Expense**							
2		Salaries and Wages	$ 23,433	$ 22,480	$ 24,487	$ 24,262	$ 23,956	$ 24,666	$ 24,940
3		Non Production Fuel and Lubricants	940	$ 1,215	$ 1,348	$ 1,177	1,278	$ 1,304	$ 1,330
4		Supplies and Services	12,489	$ 12,631	$ 13,993	$ 15,432	14,756	$ 15,051	$ 15,352
5		Travel and Accommodation	2,270	2,341	2,194	2,028	2,329	2,485	2,535
6	S. 5.0	**Total Non-Production Fuel Operation & Maintenance Expense**	**39,133**	**38,668**	**42,022**	**42,899**	**42,319**	**43,506**	**44,157**
7		Less: Corporate Donations	110	132	111	113	135	135	135
8		**Total Non-Production Fuel Operation & Maintenance Expense for GRA**	**39,023**	**38,536**	**41,911**	**42,786**	**42,185**	**43,372**	**44,023**
		Production Fuel Expense							
9	S. 4.0 L4;L6	Fuel	24,652	24,367	23,704	23,224	21,333	21,799	22,207
10	S. 4.0 L8	Purchased Power	2,978	3,618	3,462	3,014	2,068	2,113	2,153
11		**Total Production Fuel Expense**	**27,630**	**27,985**	**27,166**	**26,237**	**23,400**	**23,912**	**24,360**
		Amortization							
12	S.6.0 L1;L4	Fixed Asset Amortization (less Customer Contributions)	12,631	11,897	12,637	13,278	15,120	16,146	17,005
13	S.6.0 L2	True Up	1,839	1,839	1,839	1,839	1,288	1,288	1,288
14	S.6.0 L3	Amortization of Deferred Charges	5,348	5,587	5,639	5,708	7,865	7,977	7,809
15		**Total Amortization Expense**	**19,817**	**19,324**	**20,115**	**20,825**	**24,273**	**25,412**	**26,102**
16	S.7.0	**Total Return on Rate Base**	**19,142**	**16,363**	**12,366**	**19,426**	**20,214**	**20,516**	**20,340**
17		**Total Revenue Requirement**	**105,613**	**102,208**	**101,559**	**109,274**	**110,072**	**113,212**	**114,824**
18	S. 2.0	**Revenue at Existing Rates**	**104,836**	**91,634**	**97,261**	**99,832**	**100,201**	**100,389**	**100,396**
19		**Other Revenue**	**1,058**	**10,574**	**4,298**	**1,617**	**1,714**	**1,714**	**1,714**
20		**Total Revenue**	**105,894**	**102,208**	**101,559**	**101,449**	**101,914**	**102,103**	**102,109**
21		**Shortfall at Existing Rates**	**(281)**	**(0)**	**(0)**	**7,825**	**8,158**	**11,109**	**12,715**
22		**Average Rate Increase Required**					**8.1%**	**2.9%**	**1.4%**

Note: 2013/14 revenue requirement shows Phase I approved revenue requirement adjusted to reflect Inuvik LNG Storage and Gasification Facility Commissioning.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
REVENUE REQUIREMENT BY ZONE
(in thousands of dollars)

Line No.		2016/17 Forecast				
		Snare	**Taltson**	**Thermal**	**Common Cost**	**Total**
1	**Non-Fuel Operation & Maintenance Expense**					
2	Salaries and Wages	3,798	1,656	7,267	11,234	23,956
3	Non-Production Fuel and Lubricants	207	60	926	85	1,278
4	Supplies and Services	3,816	1,439	3,673	5,829	14,756
5	Travel and Accommodation	324	117	719	1,168	2,329
6	**Total Non-Production Fuel Operation & Maintenance Expense**	**8,145**	**3,273**	**12,585**	**18,316**	**42,319**
7	Less: Corporate Donations	78	25	31		135
8	**Total Non-Production Fuel Operation & Maintenance Expense for GRA**	**8,067**	**3,248**	**12,554**	**18,316**	**42,185**
9	**Production Fuel Expense**					
10	Fuel	932	276	20,124		21,333
11	Purchased Power			2,068		2,068
12	**Total Production Fuel Expense**	**932**	**276**	**22,192**		**23,400**
13	**Amortization**					
14	Fixed Asset Amortization (less Customer Contributions)	6,507	1,197	6,531	2,173	16,408
15	Amortization of Deferred Charges	1,416	1,300	2,830	2,320	7,865
16	**Total Amortization Expense**	**7,923**	**2,497**	**9,362**	**4,492**	**24,273**
17	**Total Return on Rate Base**	**11,166**	**1,870**	**5,005**	**2,174**	**20,214**
18	**Total Zone Specific Revenue Requirement**	**28,088**	**7,891**	**49,112**	**24,982**	**110,073**
	Common Cost Allocation by Zone					
19	*Corporate Sales Share*	*58.16%*	*18.65%*	*23.19%*		
20	*Hydro Sales Share*	*75.72%*	*24.28%*			
21	Corporate O&M Expenses	7,789	2,498	3,106		**13,394**
22	Hydro Regional O&M Expenses	576	185	0		**761**
23	Thermal Regional O&M Expenses	0	0	871		**871**
24	Distribution Related Common O&M Expenses	459	798	2,033		**3,290**
25	**Total Allocated Common Cost O&M**	**8,825**	**3,481**	**6,010**		**18,316**
26	Corporate Amortization	1,078	346	430		**1,853**
27	Hydro Regional Amortization	187	60			**247**
28	Thermal Regional Amortization			53		**53**
29	Distribution Related Common Amortization	3	4	12		**19**
30	Amortization of Deferred Charges	1,349	433	538		**2,320**
31	**Total Allocated Common Cost Amortization**	**2,617**	**843**	**1,033**		**4,492**
32	Corporate Return on Ratebase	1,039	333	426		**1,798**
33	Hydro Regional Return on Ratebase	241	77			**318**
34	Thermal Regional Return on Ratebase			52		**52**
35	Distribution Related Return on Ratebase	1	1	3		**5**
36	**Total Allocated Common Cost Return on Ratebase**	**1,281**	**412**	**481**		**2,174**
37	**Total Revenue Requirement**	**40,810**	**12,627**	**56,636**		**110,073**
38	Other Revenue	118	264	1,332		**1,714**
39	**Net Revenue Requirement**	**40,692**	**12,363**	**55,304**		**108,359**
40	**Revenue from Sales**	**38,629**	**8,961**	**52,611**		**100,201**
41	**Shortfall / (Surplus)**	**2,063**	**3,402**	**2,693**		**8,158**
42	**Average Rate Increase Required**	**5.3%**	**38.0%**	**5.1%**		**8.1%**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
REVENUE REQUIREMENT BY ZONE
(in thousands of dollars)

Line No.		2017/18 Forecast				
		Snare	**Taltson**	**Thermal**	**Common Cost**	**Total**
1	**Non-Fuel Operation & Maintenance Expense**					
2	Salaries and Wages	3,870	1,691	7,575	11,530	24,666
3	Non-Production Fuel and Lubricants	211	61	945	86	1,304
4	Supplies and Services	3,892	1,468	3,746	5,945	15,051
5	Travel and Accommodation	330	125	838	1,192	2,485
6	**Total Non-Production Fuel Operation & Maintenance Expense**	**8,304**	**3,345**	**13,105**	**18,753**	**43,506**
7	Less: Corporate Donations	78	25	31		135
8	**Total Non-Production Fuel Operation & Maintenance Expense for GRA**	**8,225**	**3,320**	**13,073**	**18,753**	**43,372**
9	**Production Fuel Expense**					
10	Fuel	951	285	20,564		21,799
11	Purchased Power			2,113		2,113
12	**Total Production Fuel Expense**	**951**	**285**	**22,676**		**23,912**
13	**Amortization**					
14	Fixed Asset Amortization (less Customer Contributions)	6,867	1,247	6,749	2,571	17,435
15	Amortization of Deferred Charges	1,416	1,300	2,830	2,432	7,978
16	**Total Amortization Expense**	**8,283**	**2,547**	**9,580**	**5,003**	**25,412**
17	**Total Return on Rate Base**	**11,405**	**1,817**	**5,043**	**2,252**	**20,516**
18	**Total Zone Specific Revenue Requirement**	**28,864**	**7,968**	**50,372**	**26,008**	**113,212**
	Common Cost Allocation by Zone					
19	*Corporate Sales Share*	*58.10%*	*18.65%*	*23.25%*		
20	*Hydro Sales Share*	*75.70%*	*24.30%*			
21	Head Office Cost	7,983	2,563	3,194		**13,739**
22	Hydro Regional Cost	589	189	0		**778**
23	Thermal Regional Cost	0	0	892		**892**
24	Distribution Related Common Cost Adjustment	466	812	2,067		**3,345**
25	**Total Allocated Common Cost**	**9,038**	**3,563**	**6,153**		**18,753**
26	Corporate Amortization	1,192	383	477		**2,051**
27	Hydro Regional Amortization	262	84			**346**
28	Thermal Regional Amortization			123		**123**
29	Distribution Related Common Amortization	7	12	33		**51**
30	Amortization of Deferred Charges	1,413	454	565		**2,432**
31	**Total Allocated Common Cost Amortization**	**2,873**	**932**	**1,197**		**5,003**
32	Corporate Return on Ratebase	1,000	321	404		**1,725**
33	Hydro Regional Return on Ratebase	278	89			**367**
34	Thermal Regional Return on Ratebase			110		**110**
35	Distribution Related Return on Ratebase	6	11	31		**49**
36	**Total Allocated Common Cost Return on Ratebase**	**1,285**	**422**	**545**		**2,252**
37	**Total Revenue Requirement**	**42,060**	**12,885**	**58,268**		**113,212**
38	Other Revenue	118	264	1,332		**1,714**
39	**Net Revenue Requirement**	**41,942**	**12,620**	**56,936**		**111,499**
40	**Revenue from Sales**	**38,634**	**8,973**	**52,781**		**100,389**
41	**Shortfall / (Surplus)**	**3,308**	**3,647**	**4,155**		**11,109**
42	**Average Rate Increase Required**	**3.1%**	**2.1%**	**3.0%**		**2.9%**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
REVENUE REQUIREMENT BY ZONE
(in thousands of dollars)

Line No.		2018/19 Forecast				
		Snare	**Taltson**	**Thermal**	**Common Cost**	**Total**
1	**Non-Fuel Operation & Maintenance Expense**					
2	Salaries and Wages	3,909	1,710	7,654	11,667	24,940
3	Non-Production Fuel and Lubricants	216	63	964	88	1,330
4	Supplies and Services	3,970	1,497	3,821	6,064	15,352
5	Travel and Accommodation	337	127	855	1,216	2,535
6	**Total Non-Production Fuel Operation & Maintenance Expense**	**8,432**	**3,397**	**13,294**	**19,035**	**44,157**
7	Less: Corporate Donations	78	25	31		135
8	**Total Non-Production Fuel Operation & Maintenance Expense for GRA**	**8,354**	**3,372**	**13,263**	**19,035**	**44,023**
9	**Production Fuel Expense**					
10	Fuel	970	296	20,941		22,207
11	Purchased Power			2,153		2,153
12	**Total Production Fuel Expense**	**970**	**296**	**23,094**		**24,360**
13	**Amortization**					
14	Fixed Asset Amortization (less Customer Contributions)	7,092	1,262	7,032	2,907	18,293
15	Amortization of Deferred Charges	1,416	1,300	2,830	2,263	7,809
16	**Total Amortization Expense**	**8,508**	**2,561**	**9,862**	**5,170**	**26,102**
17	**Total Return on Rate Base**	**11,501**	**1,730**	**4,847**	**2,262**	**20,340**
18	**Total Zone Specific Revenue Requirement**	**29,332**	**7,959**	**51,066**	**26,467**	**114,824**
	Common Cost Allocation by Zone					
19	*Corporate Sales Share*	*58.10%*	*18.66%*	*23.24%*		
20	*Hydro Sales Share*	*75.69%*	*24.31%*			
21	Head Office Cost	8,103	2,603	3,242		**13,948**
22	Hydro Regional Cost	601	193	0		**794**
23	Thermal Regional Cost	0	0	907		**907**
24	Distribution Related Common Cost Adjustment	471	822	2,092		**3,385**
25	**Total Allocated Common Cost**	**9,176**	**3,618**	**6,240**		**19,035**
26	Corporate Amortization	1,277	410	511		**2,198**
27	Hydro Regional Amortization	310	99			**409**
28	Thermal Regional Amortization			189		**189**
29	Distribution Related Common Amortization	15	25	71		**111**
30	Amortization of Deferred Charges	1,315	422	526		**2,263**
31	**Total Allocated Common Cost Amortization**	**2,916**	**957**	**1,297**		**5,170**
32	Corporate Return on Ratebase	922	296	369		**1,586**
33	Hydro Regional Return on Ratebase	300	96			**396**
34	Thermal Regional Return on Ratebase			158		**158**
35	Distribution Related Return on Ratebase	16	28	78		**122**
36	**Total Allocated Common Cost Return on Ratebase**	**1,237**	**420**	**605**		**2,262**
37	**Total Revenue Requirement**	**42,661**	**12,955**	**59,208**		**114,824**
38	Other Revenue	118	264	1,332		**1,714**
39	**Net Revenue Requirement**	**42,543**	**12,690**	**57,876**		**113,110**
40	**Revenue from Sales**	**38,635**	**8,981**	**52,780**		**100,396**
41	**Shortfall / (Surplus)**	**3,909**	**3,709**	**5,097**		**12,714**
42	**Average Rate Increase Required**	**1.4%**	**0.6%**	**1.7%**		**1.4%**

CHAPTER 4

FUEL, PURCHASED POWER AND GENERATION

4.0 FUEL, PURCHASED POWER AND GENERATION

This chapter provides a summary of the methods used to prepare Test Year forecasts for:

1. Line losses and station service.
2. Generation, including generation mix on systems with more than one type of generation.
3. Fuel efficiencies and fuel volumes.
4. Fuel prices.

This chapter also provides a comparison of forecasts for the 2016/17 Test Year with the 2013/14 forecasts from the previous General Rate Application (GRA). Information summarized in this chapter is provided in Schedules 2.0 through 2.1-3 and Schedules 4.0.1 through 4.0.4.

4.1 LOSSES AND STATION SERVICE

Line losses and station service were forecast based on a rolling average for the previous five years, consistent with the method previously reviewed and approved by the Board. A comparison of system line losses and station service forecasts at the

corporate and rate zone levels for the 2013/14 and 2016/17 Test Years is provided in Table 4.1.

Table 4.1

System Losses and Station Service – 2013/14 Test Year Forecast Compared to 2016/17 Test Year Forecast

	2013/14 Test Year	2016/17 Test Year	*Average Annual Growth*
Corporate Wide			
Line Losses (MWh)	17,872	15,421	*-4.80%*
Line Losses (% of Generation)	5.1%	4.6%	
Station Service (MWh)	13,174	13,522	*0.87%*
Station Service (% of Generation)	3.7%	4.0%	
Snare Zone			
Line Losses (MWh)	5,649	5,101	*-3.35%*
Line Losses (% of Generation)	2.8%	2.7%	
Station Service (MWh)	7,966	8,199	*0.96%*
Station Service (% of Generation)	4.0%	4.3%	
Taltson Zone			
Line Losses (MWh)	7,360	5,794	*-7.67%*
Line Losses (% of Generation)	11.0%	8.9%	
Station Service (MWh)	1,789	1,928	*2.53%*
Station Service (% of Generation)	2.7%	3.0%	
Thermal Zone			
Line Losses (MWh)	4,863	4,526	*-2.36%*
Line Losses (% of Generation)	5.8%	5.7%	
Station Service (MWh)	3,418	3,395	*-0.23%*
Station Service (% of Generation)	4.1%	4.3%	

Forecast line losses have declined by 2.5GWh from the 2013/14 Test Year to the 2016/17 Test Year. The majority of these decreases reflect decreases on the Taltson

system (1.6 GWh) where line losses have little impact on Revenue Requirement due to surplus hydro-electric generation. Line losses are forecast to decrease modestly in both absolute terms and as a percentage of generation in the Snare zone and the Thermal zone in the 2016/17 Test Year compared to the 2013/14 Test Year.

Forecast station service has increased by a small amount in the 2016/17 Test Year compared to the 2013/14 Test Year, both in absolute terms and as a percentage of system generation. This increase arises in the Snare and Taltson zones which are supplied by hydro-electric generation. A modest decrease in station service is forecast in the Thermal zone.

Taken together, line losses and station service forecasts are lower on both an absolute basis (31.0 GWh in 2013/14 compared to 28.9 GWh in 2016/17) and as a percentage of total generation (8.8% in 2013/14 compared to 8.6% in 2016/17).

4.2 GENERATION

Generation forecasts for the Test Years are the sum of sales, line losses and station service. The generation mix for systems with more than one source of generation were forecast based on the following methods:

- **Snare zone:** The generation forecast assumes that a minimum of 5 GWh of diesel generation is required for peaking and other system support functions based on a review of average actual diesel generation requirements for the years

prior to the onset of the extreme low water in 2013/14. The balance of generation is forecast to be provided by hydroelectric generation.

- **Taltson zone:** The generation forecasts assumes a minimum diesel requirement for Fort Smith and Fort Resolution based on the average diesel generation for the most recent five years. The balance of generation is forecast to be provided by hydroelectric generation.

- **Inuvik:** The proportion of generation supplied by natural gas compared to diesel is forecast based on the ratio of 40% natural gas to 60% diesel, consistent with the forecasts provided in the 2014 Phase II application.

- **Norman Wells:** The generation forecast assumes a minimum diesel requirement based on the actual diesel generation for the most recent five years. The balance of generation is forecast to be provided from purchased power.

- **Fort Simpson:** The generation forecast assumes 100,000 kWh annually of solar generation. The balance of generation is forecast to be supplied through diesel generation.

- **Colville Lake:** The generation forecast assumes 112,000 kWh annually of solar generation, consistent with the information provided by the Corporation in its

major project permit application to the Board.[1] The balance of generation is forecast to be supplied through diesel generation.

- **Fort Liard:** Beginning in 2018/19, the generation forecast assumes 30,000 kWh annually of solar generation. The balance of generation is forecast to be supplied through diesel generation.

- **Wrigley:** Beginning in 2018/19, the generation forecast assumes 8,000 kWh annually of solar generation. The balance of generation is forecast to be supplied through diesel generation.

Table 4.2 compares the generation forecasts between the 2013/14 Test Year and the 2016/17 Test Year.

Table 4.2

System Generation – 2013/14 Test Year Compared to 2016/17 Test Year

Corporate Wide	2013/14 Test Year	% of Total	2016/17 Test Year	% of Total
Total Generation (MWh)	**351,327**		**334,941**	
Generation by Source (MWh)				
Hydro	264,815	*75.4%*	249,931	*74.6%*
Diesel	64,929	*18.5%*	63,810	*19.1%*
Gas	13,249	*3.8%*	11,330	*3.4%*
Solar	0	*0.0%*	212	*0.1%*
Purchased	8,335	*2.4%*	9,658	*2.9%*

[1] Refer to Page 3 of Decision 7-2015.

The Corporation's forecast 2016/17 Test Year generation requirements have changed compared to the 2013/14 Test Year. Total generation has decreased by 16.4 GWh (4.7%) due to a decrease in sales (14.3 GWh) and a reduction in line losses and station service (2.1 GWh). The Corporation's 2016/17 forecast generation mix is similar to that forecast for the 2013/14 Test Year. Hydro generation continues to supply 75% of the

Corporation's total generation. The remaining generation requirements are supplied primarily through diesel generation with a small amount (approximately 6%) from natural gas, purchased power and solar generation.

4.3 FUEL EFFICIENCY AND FUEL VOLUMES

Fuel efficiency forecasts were prepared based on the three year weighted average method previously reviewed and approved by the Board. A weighting of 3 was assigned to the highest efficiency year, 2 for the middle efficiency year, and 1 for the lowest efficiency year. The Test Year forecasts incorporate actual fuel efficiencies for the three most recent actual years available. The Corporation adjusted the forecast efficiencies for Aklavik and Jean Marie River in 2018/19 to reflect anticipated efficiency improvements related to the Aklavik Variable Speed Generator project and the Jean Marie River G3 engine replacement.

A comparison of forecast diesel and natural gas fuel efficiencies between the 2013/14 Test Year and 2016/17 Test Year is provided in Table 4.3.

Table 4.3

Diesel Fuel Efficiency – 2013/14 Test Year Compared to 2016/17 Forecast

Fuel Efficiency	2013/14 Test Year	2016/17 Test Year	*Change*
Snare Zone diesel (kWh/litre)	3.650	3.610	*-1.10%*
Taltson Zone diesel (kWh/litre)	3.458	3.405	*-1.53%*
Thermal Zone diesel (kWh/litre)	3.553	3.589	*1.00%*
Corporate wide diesel (kWh/litre)	**3.554**	**3.587**	***0.95%***
Thermal Zone gas (kWh/m3)	3.356	3.340	*-0.48%*

Corporate wide diesel fuel efficiency has improved by approximately 1% compared to the 2013/14 Test Year. There were small decreases in average fuel efficiencies in the Snare and Taltson zones where diesel generation supplements the hydro-electric generation. In the Thermal zone, where over 90% of the Corporation's diesel generation arises in the 2016/17 Test Year, forecast diesel fuel efficiency has improved by approximately 1%.

Gas efficiency for the Thermal zone has decreased slightly (less than 1%) compared to forecasts included as part of the 2014 Phase II application reflecting additional operating experience.

Fuel volumes for the Test Years are forecast based on the forecast generation and the forecast fuel efficiencies.

4.4 FUEL PRICES

Fuel prices used for Test Year forecasts are based on the most recently available actual prices, consistent with the method used in the 2012/14 GRA. Table 4.4 compares forecast fuel prices from 2013/14 with forecast fuel prices for 2016/17. On average, diesel fuel prices are forecast to be 10% lower in 2016/17 compared to 2013/14. Purchased power prices are forecast to be approximately 40% lower. Natural gas prices are forecast to be 5% lower.

Table 4.4

Fuel Prices – 2013/14 Test Year Compared to 2016/17 Forecast

	2013/14 Fuel Price	2016/17 Fuel Price	% Change
Diesel Prices ($/litre)			
Snare Zone	1.027	0.673	-34%
Taltson Zone	1.039	0.838	-19%
Thermal Zone	1.150	1.064	-7%
Corporate Average Fuel Price	1.146	1.029	-10%
Thermal Zone Natural Gas ($/m3)	0.942	0.892	-5%
Thermal Zone Purchased Power ($/kWh)	0.357	0.214	-40%

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
2013/14 FORECAST PRODUCTION FUEL COST

Line No.	Zone		Generation (kWh)	Station Service (kWh)	Line Losses (kWh)	Plant Efficiency (kWh/L)	Fuel Required (Litres)	Fuel Price ($/L)	Fuel Cost ($000's)
DIESEL									
1	Snare Zone		1,200,000			3.650	328,770	1.027	338
	128	Fort Smith	853,500			3.477	245,479	1.036	254
	130	Fort Resolution	110,000			3.317	33,161	1.059	35
2	Taltson Zone		963,500			3.458	278,640	1.039	289
	123	Wha Ti	1,707,409	24,031	132,441	3.540	482,299	1.195	577
	124	Gameti	1,090,767	85,475	54,596	3.404	320,450	1.255	402
	127	Lutsel K'e	1,541,327	105,684	61,487	3.563	432,643	1.023	443
	131	Fort Simpson	8,258,176	272,235	509,835	3.635	2,272,132	1.076	2,445
	132	Fort Liard	2,786,631	47,394	170,125	3.654	762,608	1.005	767
	133	Wrigley	674,342	33,479	53,251	3.272	206,088	1.121	231
	134	Nahanni Butte	478,398	34,462	39,591	2.570	186,163	1.127	210
	135	Jean Marie River	313,498	43,678	24,954	2.699	116,148	1.148	133
	136	Inuvik Power - D	19,873,035	1,619,041	1,714,740	3.492	5,690,752	1.123	6,391
	137	Norman Wells - D	1,022,315	90,622	541,153	3.709	275,648	1.386	382
	138	Tuktoyaktuk	4,298,725	212,312	346,059	3.707	1,159,698	1.134	1,315
	139	Fort McPherson	3,625,602	148,923	131,103	3.625	1,000,064	1.251	1,251
	140	Aklavik	3,112,927	67,025	271,401	3.711	838,766	1.386	1,162
	141	Deline	2,855,133	67,724	224,407	3.587	795,915	1.291	1,027
	142	Fort Good Hope	2,874,190	171,878	134,673	3.671	782,973	1.125	881
	143	Paulatuk	1,530,539	67,588	61,104	3.778	405,143	1.214	492
	144	Sachs Harbour	974,726	93,306	40,743	3.302	295,228	1.152	340
	145	Tsiigehtchic	757,619	34,374	55,581	3.679	205,909	1.249	257
	146	Colville Lake	434,696	5,872	37,546	2.840	153,051	1.171	179
	147	Ulukhaktok	2,051,613	61,300	96,275	3.527	581,751	1.154	671
	148	Tulita	2,503,954	132,066	161,663	3.578	699,774	1.073	751
3	Thermal Zone		62,765,622	3,418,469	4,862,731	3.553	17,663,201	1.150	20,307
4	**Corporate - Diesel**		**64,929,122**			**3.554**	**18,270,611**	**1.146**	**20,934**

NATURAL GAS

Line No.	Zone	Generation (kWh)	Plant Efficiency (kWh/m^3)	Fuel Required (m^3)	Fuel Price (m^3)	Fuel Cost ($000's)
5	Thermal Zone	13,248,690	3.356	3,947,295	0.942	3,718
6	**Subtotal - Natural Gas**	**13,248,690**		**3,947,295**		**3,718**

PURCHASED POWER

Line No.	Zone	Generation (kWh)	Price ($/kWh)	Cost ($000's)
7	Thermal Zone	8,334,700	0.357	2,978
8	**Subtotal - Purch. Power**	**8,334,700**	**0.357**	**2,978**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
2016/17 FORECAST PRODUCTION FUEL COST

Line No.	Zone		Generation (kWh)	Station Service (kWh)	Line Losses (kWh)	Plant Efficiency (kWh/L)	Fuel Required (Litres)	Fuel Price ($/L)	Fuel Cost ($000's)
DIESEL									
1	Snare Zone		5,000,000			3.610	1,385,042	0.673	932
	128	Fort Smith	973,296			3.420	284,589	0.835	238
	130	Fort Resolution	149,957			3.310	45,304	0.853	39
2	Taltson Zone		1,123,253			3.405	329,894	0.838	276
	123	Wha Ti	1,768,844	22,065	105,109	3.580	494,091	1.035	512
	124	Gameti	1,165,198	43,609	58,260	3.520	331,022	1.063	352
	127	Lutsel K'e	1,605,821	136,356	65,426	3.570	449,810	1.068	480
	131	Fort Simpson	7,386,748	238,907	312,720	3.680	2,007,268	0.643	1,291
	132	Fort Liard	2,309,970	36,429	141,080	3.730	619,295	0.861	533
	133	Wrigley	717,113	31,304	62,103	3.310	216,650	0.861	186
	134	Nahanni Butte	422,065	21,230	33,050	2.480	170,187	0.882	150
	135	Jean Marie River	338,674	40,620	33,686	2.830	119,673	0.728	87
	136	Inuvik Power - D	16,995,739	1,545,912	1,613,117	3.590	4,734,189	1.170	5,537
	137	Norman Wells - D	182,675			3.330	54,857	1.126	62
	138	Tuktoyaktuk	4,142,352	168,060	300,762	3.690	1,122,589	1.080	1,212
	139	Fort McPherson	3,423,658	125,542	141,242	3.590	953,665	1.227	1,170
	140	Aklavik	3,255,273	64,477	234,323	3.680	884,585	1.200	1,061
	141	Deline	2,728,815	79,256	150,057	3.630	751,740	1.260	947
	142	Fort Good Hope	2,739,471	162,848	83,600	3.600	760,964	1.144	870
	143	Paulatuk	1,644,745	86,081	129,519	3.840	428,319	1.183	507
	144	Sachs Harbour	993,326	84,021	74,352	3.180	312,367	1.087	340
	145	Tsiigehtchic	728,227	31,008	54,314	3.560	204,558	1.221	250
	146	Colville Lake	536,936	35,189	65,776	2.900	185,150	1.011	187
	147	Ulukhaktok	2,102,178	63,577	127,634	3.570	588,845	1.081	636
	148	Tulita	2,498,788	125,247	138,849	3.660	682,729	1.063	726
3	Thermal Zone		57,686,616	3,141,738	3,924,978	3.589	16,072,554	1.064	17,097
4	**Corporate - Diesel**		**63,809,869**			**3.587**	**17,787,490**	**1.029**	**18,306**

NATURAL GAS

Line No.	Zone	Generation (kWh)			Plant Efficiency (kWh/m^3)	Fuel Required (m^3)	Fuel Price (m^3)	Fuel Cost ($000's)
5	Thermal Zone	11,330,492			3.340	3,392,363	0.892	3,027
6	**Subtotal - Natural Gas**	**11,330,492**	**-**	**-**		**3,392,363**		**3,027**

PURCHASED POWER

Line No.	Zone	Generation (kWh)			Price ($/kWh)	Cost ($000's)
7	Thermal Zone	9,657,893	253,586	600,871	0.214	2,068
8	**Subtotal - Purch. Power**	**9,657,893**	**253,586**	**600,871**	**0.214**	**2,068**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
2017/18 FORECAST PRODUCTION FUEL COST

Line No.	Zone		Generation (kWh)	Station Service (kWh)	Line Losses (kWh)	Plant Efficiency (kWh/L)	Fuel Required (Litres)	Fuel Price ($/L)	Fuel Cost ($000's)
DIESEL									
1	Snare Zone		5,000,000			3.610	1,385,042	0.686	951
	128	Fort Smith	982,360			3.420	287,240	0.852	245
	130	Fort Resolution	152,512			3.310	46,076	0.870	40
2	Taltson Zone		1,134,872			3.405	333,316	0.854	285
	123	Wha Ti	1,768,468	20,619	110,877	3.580	493,985	1.056	522
	124	Gameti	1,181,988	50,324	59,099	3.520	335,792	1.084	364
	127	Lutsel K'e	1,611,086	140,814	62,906	3.570	451,285	1.090	492
	131	Fort Simpson	7,507,976	238,831	303,378	3.680	2,040,211	0.656	1,338
	132	Fort Liard	2,270,595	36,743	136,559	3.730	608,739	0.878	534
	133	Wrigley	713,491	31,820	61,895	3.310	215,556	0.878	189
	134	Nahanni Butte	414,798	20,734	31,784	2.480	167,257	0.900	150
	135	Jean Marie River	353,077	42,993	38,865	2.830	124,762	0.743	93
	136	Inuvik Power - D	17,020,003	1,571,483	1,587,613	3.590	4,740,948	1.193	5,656
	137	Norman Wells - D	180,384			3.330	54,169	1.148	62
	138	Tuktoyaktuk	4,128,959	167,762	284,320	3.690	1,118,959	1.101	1,232
	139	Fort McPherson	3,410,057	127,223	144,957	3.590	949,877	1.252	1,189
	140	Aklavik	3,239,754	64,926	220,756	3.680	880,368	1.224	1,077
	141	Deline	2,738,415	77,694	142,106	3.630	754,384	1.286	970
	142	Fort Good Hope	2,754,138	164,572	75,130	3.600	765,038	1.167	893
	143	Paulatuk	1,641,002	87,295	133,118	3.840	427,344	1.207	516
	144	Sachs Harbour	999,088	83,240	77,881	3.180	314,179	1.109	348
	145	Tsiigehtchic	727,831	31,810	53,042	3.560	204,447	1.246	255
	146	Colville Lake	549,595	39,768	70,849	2.900	189,515	1.031	195
	147	Ulukhaktok	2,105,175	63,227	117,529	3.570	589,685	1.103	650
	148	Tulita	2,518,897	126,868	135,703	3.660	688,223	1.084	746
3	Thermal Zone		57,834,776	3,188,744	3,848,367	3.589	16,114,724	1.084	17,472
4	**Corporate - Diesel**		**63,969,648**			**3.587**	**17,833,081**	**1.049**	**18,707**

NATURAL GAS

Line No.	Zone	Generation (kWh)			Plant Efficiency (kWh/m^3)	Fuel Required (m^3)	Fuel Price (m^3)	Fuel Cost ($000's)
5	Thermal Zone	11,346,668	256,707	604,746	3.340	3,397,206	0.910	3,092
6	**Subtotal - Natural Gas**	**11,346,668**	**256,707**	**604,746**		**3,397,206**		**3,092**

PURCHASED POWER

Line No.	Zone	Generation (kWh)	Price ($/kWh)	Cost ($000's)
7	Thermal Zone	9,673,674	0.218	2,113
8	**Subtotal - Purch. Power**	**9,673,674**	**0.218**	**2,113**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
2018/19 FORECAST PRODUCTION FUEL COST

Line No.	Zone		Generation (kWh)	Station Service (kWh)	Line Losses (kWh)	Plant Efficiency (kWh/L)	Fuel Required (Litres)	Fuel Price ($/L)	Fuel Cost ($000's)
DIESEL									
1	Snare Zone		5,000,000			3.610	1,385,042	0.700	970
	128	Fort Smith	995,764			3.420	291,159	0.869	253
	130	Fort Resolution	159,912			3.310	48,312	0.888	43
2	Taltson Zone		1,155,676			3.404	339,471	0.872	296
	123	Wha Ti	1,761,609	20,718	110,804	3.580	492,070	1.077	530
	124	Gameti	1,178,032	50,614	58,902	3.520	334,668	1.106	370
	127	Lutsel K'e	1,619,743	143,439	64,224	3.570	453,709	1.111	504
	131	Fort Simpson	7,503,987	243,957	311,575	3.680	2,039,127	0.669	1,364
	132	Fort Liard	2,296,629	35,864	148,025	3.730	615,718	0.895	551
	133	Wrigley	718,275	32,290	59,960	3.310	217,001	0.895	194
	134	Nahanni Butte	418,493	21,846	31,600	2.480	168,747	0.918	155
	135	Jean Marie River	361,034	44,362	42,751	3.000	120,345	0.758	91
	136	Inuvik Power - D	17,019,149	1,592,745	1,609,245	3.590	4,740,710	1.217	5,769
	137	Norman Wells - D	175,699			3.330	52,762	1.171	62
	138	Tuktoyaktuk	4,142,934	166,508	279,800	3.690	1,122,746	1.123	1,261
	139	Fort McPherson	3,376,908	126,380	159,124	3.590	940,643	1.277	1,201
	140	Aklavik	3,248,328	64,461	218,171	3.900	832,905	1.248	1,040
	141	Deline	2,778,607	77,987	171,129	3.630	765,457	1.311	1,004
	142	Fort Good Hope	2,781,653	167,681	77,304	3.600	772,681	1.190	920
	143	Paulatuk	1,636,824	87,268	138,481	3.840	426,256	1.231	525
	144	Sachs Harbour	1,000,826	81,205	84,333	3.180	314,725	1.131	356
	145	Tsiigehtchic	730,881	32,346	54,565	3.560	205,304	1.271	261
	146	Colville Lake	553,747	38,016	73,532	2.900	190,947	1.052	201
	147	Ulukhaktok	2,111,703	63,538	116,196	3.570	591,514	1.125	665
	148	Tulita	2,530,192	128,908	135,550	3.660	691,309	1.106	764
3	Thermal Zone		57,945,253	3,220,133	3,945,271	3.601	16,089,345	1.106	17,788
4	**Corporate - Diesel**		**64,100,930**			**3.598**	**17,813,858**	**1.070**	**19,053**

NATURAL GAS

Line No.	Zone	Generation (kWh)			Plant Efficiency (kWh/m^3)	Fuel Required (m^3)	Fuel Price (m^3)	Fuel Cost ($000's)
5	Thermal Zone	11,346,100	248,816	601,784	3.340	3,397,036	0.928	3,154
6	**Subtotal - Natural Gas**	**11,346,100**	**248,816**	**601,784**		**3,397,036**		**3,154**

PURCHASED POWER

Line No.	Zone	Generation (kWh)	Price ($/kWh)	Cost ($000's)
7	Thermal Zone	9,664,259	0.223	2,153
8	**Subtotal - Purch. Power**	**9,664,259**	**0.223**	**2,153**

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Schedule 4.1

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Schedule 4.2

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CHAPTER 5

OPERATING AND MAINTENANCE EXPENSES

5.0 OPERATING AND MAINTENANCE EXPENSES

NTPC's forecasts for total operating and maintenance expenses for 2016/17, 2017/18 and 2018/19 are set out in Schedules 5.0 to 5.3-3. A summary of the major components of these schedules is included in Table 5.1 below.

Table 5.1
O&M Expense – 2013/14 Approved GRA Compared to 2016/17 – 2018/19

		Test Year		
Non-Production Fuel O&M Expense	**2013/14 Forecast**	**2016/17 Forecast**	**2017/18 Forecast**	**2018/19 Forecast**
Salaries and Wages	23,433	23,956	24,666	24,940
Non Production Fuel and Lubricants	940	1,279	1,304	1,330
Supplies and Services	12,489	14,756	15,051	15,352
Travel and Accommodation	2,270	2,329	2,485	2,535
Total Non-Production Fuel O&M Expense	39,133	42,320	43,506	44,157
Less: Corporate Donations	110	135	135	135
Total Non-Production Fuel O&M Expense	39,023	42,185	43,372	44,023

For the 2012/14 GRA the budgeting and tracking system for operations and maintenance expenses did not use FERC accounts. NTPC employed a tracking and budgeting system by cost center consistent with the Corporation's accounting system. For the 2012/14 GRA this was addressed in response to YK/HR.NTPC-1 and at the

hearing. For the 2016/19 GRA, the Corporation budgets and tracks costs by cost center as well as by function group as shown in Schedules 5.0 to 5.1-3 and with variance explanations in Schedule 5.2. When comparing the 2013/14 Test Year to the 2016/17 Test Year the variances by function are mainly attributed to the different forecasting methods.

The Corporation's non-fuel O&M expenses have increased by $3.162 million from the 2013/14 Test Year to the 2016/17 Test Year and a further $1.187 million in 2017/18 and $0.651 million in 2018/19. Overall, the changes that have occurred in the Corporation's operating and maintenance expenses since the 2013/14 Test Year reflect strategic initiatives undertaken by the Corporation to increase communications with customers and stakeholders, the development of a virtual call center, improvements to health and safety systems, implementation of an asset management framework, implementation of a computer maintenance management system, improvements in preventative maintenance, implementation of a lone worker system, implementation of Automated Metering Infrastructure, improvements in human resource management, recruitment and retention and the development of the Power System Plan.

5.1 SALARIES AND WAGES

Salaries and wages include all salaries[1] for all full time employees and casual employees as well as related benefits such as Employment Insurance, Canada Pension

[1] Regular salaries, overtime, standby pay, call-back pay and at-risk compensation.

Plan, Health Insurance, Public Service Pension Plan, Northern Living Allowance, and Local Differential Payments.

Forecast salaries of $23.956 million for 2016/17 reflect a number of strategic initiatives to respond efficiently to changes in the Corporation's business environment. The $0.523 million increase in 2016/17 salaries compared to the 2013/14 Test Year reflects average increases resulting from collective agreements, annual experience increments for employees and increases to the employer's portion of employee benefits as well as changes in staff complement.

Since the 2013/14 Test Year the Corporation has added 12 Full Time Equivalent ("FTE") positions. Table 5.2 outlines the change in FTE's from the 2013/14 Test Year.

Table 5.2

FTE change from 2013/14 Test Year to 2016/17 Test Year

2013/14 Test Year FTE	188.75
Removal of Board of Directors	-1.5
Increased Customer Service	3.5
Developmental Positions	4
Plant Superintendents	1
Improved Preventative Maintenance	2
Increased Regulation	3
2016/17 Test Year FTE	200.75

- In May 2016 as a cost saving measure the Corporation's Board of Directors were replaced with a Board of GNWT Deputy Ministers resulting in the elimination of 1.5 FTE positions.

- The Corporation as discussed in Section 1.3 has a number of customer service excellence initiatives and a new strategic direction to improve and meet the needs of our customers. As part of that initiative a new Customer Service Division has been established with the creation of positions for a Director, a Manager, and a Distribution Technologist. As well one Customer Service Representative has been increased from part time to full time. In conjunction with these new positons the Corporation has refocused existing positions to improve customer service.

- The Corporation has established four developmental positions for succession planning and to mitigate the risks associated with loss of knowledge due to an aging workforce. These positions include two Hydro Plant Operators, Stock keepers, and a Diesel Mechanic.

- One Plant Superintendent has increased by 0.25 FTE and one Plant Superintendent has changed from being a contract worker to an employee.

- Utilizing the Asset Condition Assessments and Power System Plan the Corporation has an increased focus on preventive maintenance and asset management. The Corporation has created two new FTE's, a CMMS Specialist and a Maintenance Planner and refocused four existing positions to improve preventive maintenance, reduce unexpected losses and manage aging assets in a cost effective manner.

- The Corporation has also added 3 FTE's due to increased regulatory compliance and reporting, a Management Accountant for regulatory and PSAS accounting, an Environmental Licensing Specialist and a Construction Health and Safety Coordinator.

The Corporation is also strengthening the next generation of NTPC employees and increasing succession plans through creation of 22 part time summer student positions assisting Plant Superintendents in remote communities. This is for the 2017/18 and 2018/19 Test Years and increased salary and wages by $0.220 million in 2017/18 and $0.224 million in 2018/19.

5.2 NON PRODUCTION FUEL AND LUBRICANTS

The cost of vehicle fuel, building heat and lube grease and antifreeze has increased from $0.940 million in 2013/14 Test Year to $1.278 million in 2016/17. The increase is driven by increased consumption of consumables (lube and oil) due to the increased preventative maintenance program and higher forecast costs for building heat than in the 2013/14 Test Year.

5.3 SUPPLIES AND SERVICES

Supplies and services represent the cost of maintaining the plants and equipment and include such costs as supplies, freight, contractors, professional development and administration. The cost of supplies and services has increased from $12.489 million in the 2013/14 Test Year to $14.756 million in the 2016/17 Test Year. $0.765 million of the

increase is associated with inflation over the three year period. Other notable changes since 2013/14 are:

- $0.500 million decrease due to the replacement of the Board of Directors.
- $0.150 million for increased brushing expenses. As discussed in previous rate applications brushing expenses vary notably from year to year and the Corporation is managing to a budget of approximately $0.700 million.
- $0.180 million for increased maintenance agreements related to boiler inspections, IT hardware and software maintenance costs and increased building maintenance costs due to aging infrastructure.
- $0.200 million for employee training programs. The Corporation is moving towards and maintaining an industry best practice training program. The increase is driven by mandatory safety training in compliance with the new Health and Safety Management system and NTPC's COR certification.
- $0.225 million for increased legal, risk management and safety compliance. The Corporation has implemented a new Health and Safety Management system which has an increased safety consulting costs. The Corporation is implementing a revised Enterprise Risk Management framework to identify and manage top corporate risks. Legal costs have increased as the Corporation revised all procurement contracts for increased risk management and safety compliance and to update the terms and conditions for standard business practices. The

Corporation also faces increased legal compliance in areas such as safety, civil claims, contractual risk management and privacy protection.

- $0.340 million increase related to hydro maintenance and camp expenses. Camp expenses include the cost of food, cooking and maintaining the hydro camps. The cost of food has increased significantly since the 2013/14 Test Year. Other increases include annual shut down costs as OEM experts are used and preventative maintenance.

- $0.500 million for human resource management such as recruitment, Hay Plan employee evaluations, employee retention and satisfaction plans. As discussed in section 1.3 the Corporation has a strategic goal to develop and maintain a highly skilled workforce that reflects the demographics of the NWT. To accomplish this goal the Corporation has completed a number of employee surveys on corporate culture and employee satisfaction, based on the survey gap analysis, the Corporation launched a new Employee Recognition Program, continuing to strengthen our employee workforce through the apprenticeship program, as well as a Scholarship Program. The Corporation has also partnered with Aurora College to deliver a comprehensive Management Development Program. The Corporation will also be implementing a new online software solution for completing and managing employee performance appraisals, this system will also provide support in succession planning. A new Careers website was recently launched based on a comprehensive market strategy for recruitment.

5.4 TRAVEL AND ACCOMMODATION

Travel and accommodation expense includes all the travel, accommodation and meal costs associated with staff travel for operational, training and professional development purposes. The cost of travel and accommodation has increased from $2.270 million in the 2013/14 Test Year to $2.329 million in 2016/17. NTPC has been able to maintain lower travel and accommodation costs through increased telecommunication solutions. The increases in 2017/18 and 2018/19 largely represent inflation except for $0.110 million in training travel associated with the 22 part time summer students and $0.112 million in 2018/19.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - NTPC

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Generation	12,582	13,537	15,023	15,239	14,949	15,536	15,754
	Hydro Generation							
8474	Telecontrol system expense	452	397	363	409	240	244	247
8475	SCADA control centre expense	372	141	167	122	204	207	210
8600	Electrical - operation & maintenance management	386	261	233	265	216	219	221
8601	Hydro generation expense	847	1,074	1,008	1,199	1,060	1,077	1,090
8602	Hydro camp expenses	230	501	494	558	502	513	523
8603	Mechanical - operation & maintenance management	8	14	103	17	25	26	26
8604	Hydro maintenance of powerhouse & structures	340	165	193	149	186	190	193
8606	Hydro maintenance of dams, waterways and reservoirs	75	76	107	99	123	125	127
8607	Hydro maintenance of other	170	173	110	138	150	152	154
8608	Mechanical - Overhaul hydro unit	0	0	0	(63)	0	2	4
8609	Electrical - Overhaul hydro unit	0	(0)	0	0	0	0	0
8618	Mechanical - Maintenance hydro unit	0	13	145	542	465	472	479
8619	Electrical - Maintenance hydro unit	135	174	176	223	98	100	102
8628	Mechanical - Hydro maintenance of plant auxiliaries	0	10	16	16	27	28	28
8629	Electrical - Hydro maintenance of plant auxiliaries	92	85	145	139	116	118	120
	Thermal Generation							
8468	Thermal Supervisory Systems	70	40	62	91	198	201	204
8677	System control expense	0	0	0	0	0	0	0
8637	Maintenance planning	0	8	124	151	167	169	170
8639	Apprentice Positions - Electricians	12	0	1	0	0	0	0
8640	Thermal operation management	958	914	627	535	651	663	670
8642	Thermal generation expense	3,019	3,755	4,361	4,145	3,932	4,312	4,360
8643	Thermal generation maintenance management	298	188	474	542	640	652	659
8644	Maintenance of th. gen. powerhouse, plant & auxiliaries	2,289	3,267	2,471	2,330	2,267	2,314	2,352
8646	Overhaul thermal generation unit	0	0	0	0	0	0	0
8647	Maintenance costs for emergency genset units	0	20	8	25	24	24	25
8648	Mechanical - Overhaul thermal generation unit	0	0	0	0	0	0	0
8649	Electrical - Overhaul thermal generation unit	0	0	0	0	0	0	0
8657	Thermal generation unit maintenance	2,317	1,892	2,264	2,222	2,163	2,197	2,232
8658	Mechanical - Thermal generation unit maintenance	508	265	575	422	452	465	473
8659	Electrical - Thermal generation unit maintenance	0	52	279	65	57	59	60
8660	LNG offloading	0	0	11	0	0	0	0
8662	Maintenance of LNG plant	0	0	48	5	4	4	4
8668	Mechanical - Maint. of th. gen. powerhouse, plant & auxiliaries	0	0	120	395	390	398	406
8669	Electrical - Maint. of th. gen. powerhouse, plant & auxiliaries	0	0	254	315	282	296	299
8673	Transmission line substation structures & equipment	0	0	1	164	290	293	296
	Alternative Generation							
8635	Operation and maintenance of alternative energy facilities	0	7	16	10	9	10	10
	Residual Heat							
8697	Residual heat maintenance	5	46	66	10	10	10	10
	Transmission	780	358	1,048	775	720	733	747
8870	Transmission line management	22	5	1	0	0	0	0
8871	Transmission line overhead expense	111	48	79	165	160	162	164
8872	Transmission brushing expense	418	43	640	610	560	571	583
8873	Transmission line substation structures and equipment	230	261	328	0	0	0	0
	Distribution	3,407	3,201	3,064	1,318	2,934	2,974	3,014
8810	T&D - Vehicle operations and maintenance	0	210	170	61	179	182	186
8811	T&D - Equipment operations and maintenance	0	59	55	155	110	112	114
8812	T&D lineshop costs	0	61	59	67	94	95	97
8880	Distribution line management	116	129	15	0	0	0	0
8881	Distribution brushing expense	143	46	46	75	150	153	156
8882	Distribution overhead lines	2,598	1,894	1,986	839	2,134	2,160	2,186
8883	Distribution line underground	9	0	1	0	0	0	0
8884	Distribution customer demand meters	16	7	6	0	0	0	0
8885	Distribution line primary equipment	50	30	16	0	0	0	0
8887	Distribution line streetlights	86	124	45	0	43	43	43
8888	Distribution substation expense	12	7	19	0	0	0	0
8889	Distribution line customer meter reading	314	280	271	106	162	163	165
8890	Apprentice linepersons' training	0	0	1	0	10	10	10
8892	Trouble Calls	64	354	374	15	54	55	56
	Billing & Customer Accounting	1,408	266	257	490	465	470	475
8886	Distribution line customer service	1,408	266	257	490	465	470	475
	General Expense Functions	3,491	3,307	2,899	3,489	2,842	2,893	2,944

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - NTPC

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
8480	Hazardous waste disposal	23	60	109	78	110	112	114
8482	Water Testing	1	2	0	0	0	0	0
8483	Hazardous Materials Cleanup	0	4	0	2	2	2	2
8486	Safety	0	6	6	7	6	6	6
8487	Environmental	349	147	117	81	73	74	76
8710	OPERATIONS - Vehicle operations and maintenance	587	831	575	603	533	543	553
8711	OPERATIONS - Equipment operations and maintenance	352	89	79	124	199	203	207
8717	Housing O&M Expense	239	308	241	335	371	378	384
8719	Building, yard and fence maint. expense	543	663	675	783	901	916	931
8720	Stores warehouse expense	252	199	113	344	33	34	35
8721	Fuel storage facilities	66	11	5	10	17	17	18
8722	Stockkeeper	0	0	50	94	125	126	128
8732	Network Support Operation & Maintenance	1,076	987	928	1,028	473	483	492
	Administration Functions	2,764	2,214	2,158	2,060	2,094	2,147	2,189
8730	Administration O&M	2,764	2,214	2,158	2,060	2,094	2,147	2,189
	Common Costs	14,699	15,785	17,572	19,527	18,316	18,753	19,035
8138	Distribution related (Billing)	251	59	224	250	268	271	274
8162	Distribution related (CSM maintenance)		27	105	40	60	61	62
8163	Distribution related (Service Desk Management)	113	0	21	153	144	145	147
8803	Distribution related (Customer service)	347	1,072	997	1,373	1,568	1,591	1,609
8880	Distribution line management		105	115	379	363	367	371
8882	Distribution overhead lines	128	241	331	1,925	887	909	921
8890	Apprentice Linepersons' training	72	5	48	52	1	1	1
	Corporate	12,596	13,248	13,991	14,183	13,394	13,739	13,948
	Regional	1,191	1,030	1,739	1,172	1,632	1,670	1,702
	Grand Total	39,130	38,668	42,022	42,899	42,319	43,506	44,157

Common Cost Allocation Formula

Step 1: [Corp Dist cost] x [Zone's share in corporate retail sales]
Step 2: [Regional dist cost] x [Zone's share in regional retail sales]
Step 3: [Other corporate cost] x [Zone's share in corporate sales]
Step 4: [Other regional area cost] x [Zone's share in regional sales]
Step 5: Step 1 + Step 2 + Step 3 + Step 4

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Snare Zone

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Generation	3,843	4,266	5,478	6,182	5,297	5,392	5,469
	Hydro Generation							
8474	Telecontrol system expense	341	266	276	322	164	166	169
8475	SCADA control centre expense	347	125	147	97	185	187	190
8600	Electrical - operation & maintenance management	251	111	86	135	85	86	87
8601	Hydro generation expense	591	727	704	938	845	855	865
8602	Hydro camp expenses	181	465	463	516	464	473	482
8603	Mechanical - operation & maintenance management	6	14	103	17	25	26	26
8604	Hydro maintenance of powerhouse & structures	328	146	166	115	161	164	168
8606	Hydro maintenance of dams, waterways and reservoirs	66	68	78	92	105	107	109
8607	Hydro maintenance of other	85	99	43	23	20	20	20
8608	Mechanical - Overhaul hydro unit		0	0	12	0	0	0
8609	Electrical - Overhaul hydro unit		(0)		0	0	0	0
8618	Mechanical - Maintenance hydro unit		13	145	542	465	472	479
8619	Electrical - Maintenance hydro unit	103	158	151	219	72	73	75
8628	Mechanical - Hydro maintenance of plant auxiliaries		10	16	16	27	28	28
8629	Electrical - Hydro maintenance of plant auxiliaries	60	52	125	116	82	84	85
	Thermal Generation							
8468	Thermal Supervisory Systems	3	3	8	11	39	39	40
8677	System control expense				0	0	0	0
8637	Maintenance planning		8	124	151	167	169	170
8639	Apprentice Positions - Electricians		0	1	0	0	0	0
8640	Thermal operation management	346	346	175	118	87	88	89
8642	Thermal generation expense	374	575	1,042	1,393	846	861	872
8643	Thermal generation maintenance management	26	15	55	173	285	288	291
8644	Maintenance of th. gen. powerhouse, plant & auxiliaries	597	940	481	0	0	0	0
8646	Overhaul thermal generation unit							
8647	Maintenance costs for emergency genset units		0	0	0	0	0	0
8648	Mechanical - Overhaul thermal generation unit							
8649	Electrical - Overhaul thermal generation unit							
8657	Thermal generation unit maintenance	136	0	0	0	0	0	0
8658	Mechanical - Thermal generation unit maintenance	1	115	527	343	334	344	350
8659	Electrical - Thermal generation unit maintenance		12	203	31	29	29	30
8660	LNG offloading			0	0	0	0	0
8662	Maintenance of LNG plant			0	0	0	0	0
8668	Mechanical - Maint. of th. gen. powerhouse, plant & auxiliaries			117	383	359	366	373
8669	Electrical - Maint. of th. gen. powerhouse, plant & auxiliaries		0	241	283	266	280	283
8673	Transmission line substation structures & equipment			1	138	185	187	189
	Alternative Generation							
8635	Operation and maintenance of alternative energy facilities		0		0	0	0	0
	Residual Heat							
8697	Residual heat maintenance	0	0	0	0	0	0	0
	Transmission	432	252	174	92	387	395	402
8870	Transmission line management	19	0	0	0	0	0	0
8871	Transmission line overhead expense	65	25	26	92	107	109	111
8872	Transmission brushing expense	193	29	71	0	280	286	291
8873	Transmission line substation structures and equipment	155	198	77	0	0	0	0
	Distribution	798	521	513	206	453	458	464
8810	T&D - Vehicle operations and maintenance		13	23	10	36	37	37
8811	T&D - Equipment operations and maintenance		10	10	25	30	31	31
8812	T&D lineshop costs		0	0	0	0	0	0
8880	Distribution line management	25	0	1	0	0	0	0
8881	Distribution brushing expense	31	3	0	75	40	41	42
8882	Distribution overhead lines	691	434	427	96	347	350	354
8883	Distribution line underground	0	0	0	0	0	0	0
8884	Distribution customer demand meters	2	0	0	0	0	0	0
8885	Distribution line primary equipment	14	2	0	0	0	0	0
8887	Distribution line streetlights	7	2	5	0	0	0	0
8888	Distribution substation expense	4	5	2	0	0	0	0
8889	Distribution line customer meter reading	19	25	18	0	0	0	0
8890	Apprentice linepersons' training		0	0	0	0	0	0
8892	Trouble Calls	4	26	27	0	0	0	0
	Billing & Customer Accounting	234	7	6	35	31	31	32
8886	Distribution line customer service	234	7	6	35	31	31	32
	General Expense Functions	1,099	1,253	1,116	1,305	810	824	839

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Snare Zone

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
8480	Hazardous waste disposal	13	(3)	16	25	66	67	68
8482	Water Testing	1	0		0	0	0	0
8483	Hazardous Materials Cleanup	0	1	0	0	0	0	0
8486	Safety		6	6	7	6	6	6
8487	Environmental	116	39	25	11	20	21	21
8710	OPERATIONS - Vehicle operations and maintenance	71	255	168	145	91	93	94
8711	OPERATIONS - Equipment operations and maintenance	242	70	68	110	99	101	103
8717	Housing O&M Expense	39	40	15	15	19	19	19
8719	Building, yard and fence maint. expense	151	192	228	139	155	158	161
8720	Stores warehouse expense	193	128	48	156	30	30	31
8721	Fuel storage facilities	2	8	5	5	13	13	14
8722	Stockkeeper			50	94	125	126	128
8732	Network Support Operation & Maintenance	272	518	487	598	186	190	194
	Administration Functions	1,322	1,076	1,181	1,027	1,168	1,203	1,226
8730	Administration O&M	1,322	1,076	1,181	1,027	1,168	1,203	1,226
	Common Costs	7,945	8,224	9,030	9,195	8,825	9,038	9,176
8138	Distribution related (Billing)	33	5	18	20	35	35	36
8162	Distribution related (CSM maintenance)		2	8	3	8	8	8
8163	Distribution related (Service Desk Management)	15		2	12	19	19	19
8803	Distribution related (Customer service)	46	83	79	108	206	208	211
8880	Distribution line management		25	4	52	63	63	64
8882	Distribution overhead lines	35	38	63	182	129	132	133
8890	Apprentice Linepersons' training	26		6	5	0	0	0
	Corporate	7,320	7,673	8,182	8,292	7,789	7,983	8,103
	Regional	468	399	667	521	576	589	601
	Grand Total	15,673	15,599	17,498	18,043	16,970	17,341	17,608

Common Cost Allocation Formula

Step 1: [Corp Dist cost] x [Zone's share in corporate retail sales]
Step 2: [Regional dist cost] x [Zone's share in regional retail sales]
Step 3: [Other corporate cost] x [Zone's share in corporate sales]
Step 4: [Other regional area cost] x [Zone's share in regional sales]
Step 5: Step 1 + Step 2 + Step 3 + Step 4

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Taltson Zone

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Generation	1,217	1,437	1,295	1,452	1,552	1,596	1,620
	Hydro Generation							
8474	Telecontrol system expense	111	130	87	80	73	74	75
8475	SCADA control centre expense	25	15	19	22	19	20	20
8600	Electrical - operation & maintenance management	135	150	148	130	131	132	134
8601	Hydro generation expense	256	346	304	261	215	222	225
8602	Hydro camp expenses	49	37	30	43	39	40	40
8603	Mechanical - operation & maintenance management	1	0	0	0	0	0	0
8604	Hydro maintenance of powerhouse & structures	11	19	27	34	25	25	26
8606	Hydro maintenance of dams, waterways and reservoirs	9	8	29	7	18	18	18
8607	Hydro maintenance of other	86	74	67	116	130	132	134
8608	Mechanical - Overhaul hydro unit		0	(0)	(75)	0	2	4
8609	Electrical - Overhaul hydro unit		(0)		0	0	0	0
8618	Mechanical - Maintenance hydro unit		0	0	0	0	0	0
8619	Electrical - Maintenance hydro unit	32	16	25	4	26	26	27
8628	Mechanical - Hydro maintenance of plant auxiliaries		0	0	0	0	0	0
8629	Electrical - Hydro maintenance of plant auxiliaries	31	33	20	24	34	34	35
	Thermal Generation							
8468	Thermal Supervisory Systems	1	0	2	4	1	1	1
8677	System control expense				0	0	0	0
8637	Maintenance planning		0	0	0	0	0	0
8639	Apprentice Positions - Electricians		0	0	0	0	0	0
8640	Thermal operation management	20	29	38	34	38	39	39
8642	Thermal generation expense	123	289	261	329	294	312	316
8643	Thermal generation maintenance management	1	2	3	0	0	0	0
8644	Maintenance of th. gen. powerhouse, plant & auxiliaries	172	191	152	249	221	224	228
8646	Overhaul thermal generation unit							
8647	Maintenance costs for emergency genset units		0	0	0	0	0	0
8648	Mechanical - Overhaul thermal generation unit							
8649	Electrical - Overhaul thermal generation unit							
8657	Thermal generation unit maintenance	154	98	82	165	184	187	190
8658	Mechanical - Thermal generation unit maintenance	0	0	0	0	0	0	0
8659	Electrical - Thermal generation unit maintenance		0	0	0	0	0	0
8660	LNG offloading			0	0	0	0	0
8662	Maintenance of LNG plant			0	0	0	0	0
8668	Mechanical - Maint. of th. gen. powerhouse, plant & auxiliaries			0	0	0	0	0
8669	Electrical - Maint. of th. gen. powerhouse, plant & auxiliaries		0	0	0	0	0	0
8673	Transmission line substation structures & equipment			0	26	105	106	107
	Alternative Generation							
8635	Operation and maintenance of alternative energy facilities		0		0	0	0	0
	Residual Heat							
8697	Residual heat maintenance	0	0	0	0	0	0	0
	Transmission	349	106	874	683	332	338	345
8870	Transmission line management	3	5	1	0	0	0	0
8871	Transmission line overhead expense	46	24	53	73	52	53	54
8872	Transmission brushing expense	224	14	569	610	280	286	291
8873	Transmission line substation structures and equipment	75	63	251	0	0	0	0
	Distribution	588	553	653	385	645	653	661
8810	T&D - Vehicle operations and maintenance		33	61	2	60	61	62
8811	T&D - Equipment operations and maintenance		14	7	50	20	20	21
8812	T&D lineshop costs		0	0	0	0	0	0
8880	Distribution line management	9	3	0	0	0	0	0
8881	Distribution brushing expense	0	1	9	0	35	36	36
8882	Distribution overhead lines	520	415	475	307	524	530	536
8883	Distribution line underground	9	0	1	0	0	0	0
8884	Distribution customer demand meters	2	2	4	0	0	0	0
8885	Distribution line primary equipment	10	14	6	0	0	0	0
8887	Distribution line streetlights	14	11	6	0	0	0	0
8888	Distribution substation expense	8	2	15	0	0	0	0
8889	Distribution line customer meter reading	15	7	12	21	5	6	6
8890	Apprentice linepersons' training		0	0	0	0	0	0
8892	Trouble Calls	2	51	57	6	0	0	0
	Billing & Customer Accounting	293	47	65	89	108	109	110
8886	Distribution line customer service	293	47	65	89	108	109	110
	General Expense Functions	452	335	257	271	407	414	422

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Taltson Zone

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
8480	Hazardous waste disposal	2	10	8	10	6	6	6
8482	Water Testing	0	0		0	0	0	0
8483	Hazardous Materials Cleanup	0	0	0	1	1	1	1
8486	Safety		0	0	0	0	0	0
8487	Environmental	28	13	18	10	17	17	17
8710	OPERATIONS - Vehicle operations and maintenance	142	89	49	51	56	57	58
8711	OPERATIONS - Equipment operations and maintenance	28	1	3	9	99	101	103
8717	Housing O&M Expense	14	16	15	26	33	33	34
8719	Building, yard and fence maint. expense	114	85	76	77	135	137	139
8720	Stores warehouse expense	11	8	3	7	0	0	0
8721	Fuel storage facilities	0	0	0	1	0	0	0
8722	Stockkeeper			0	0	0	0	0
8732	Network Support Operation & Maintenance	112	112	85	80	60	62	63
	Administration Functions	502	254	232	198	230	234	239
8730	Administration O&M	502	254	232	198	230	234	239
	Common Costs	2,672	3,053	3,321	3,879	3,481	3,563	3,618
8138	Distribution related (Billing)	53	14	53	58	61	62	62
8162	Distribution related (CSM maintenance)		6	25	9	14	14	14
8163	Distribution related (Service Desk Management)	24		5	36	33	33	33
8803	Distribution related (Customer service)	73	256	238	321	358	363	367
8880	Distribution line management		76	13	154	109	110	112
8882	Distribution overhead lines	56	118	191	544	224	230	233
8890	Apprentice Linepersons' training	42		19	16	0	0	0
	Corporate	2,280	2,455	2,567	2,577	2,498	2,563	2,603
	Regional	145	128	209	162	185	189	193
	Grand Total	6,072	5,785	6,697	6,957	6,754	6,908	7,015

Common Cost Allocation Formula

Step 1: [Corp Dist cost] x [Zone's share in corporate retail sales]
Step 2: [Regional dist cost] x [Zone's share in regional retail sales]
Step 3: [Other corporate cost] x [Zone's share in corporate sales]
Step 4: [Other regional area cost] x [Zone's share in regional sales]
Step 5: Step 1 + Step 2 + Step 3 + Step 4

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Thermal Zone

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Generation	7,521	7,834	8,250	7,605	8,100	8,548	8,665
	Hydro Generation							
8474	Telecontrol system expense	0	1	0	8	3	3	3
8475	SCADA control centre expense	0	1	2	3	0	0	0
8600	Electrical - operation & maintenance management	0	0	0	0	0	0	0
8601	Hydro generation expense	0	0	0	0	0	0	0
8602	Hydro camp expenses	0	0	0	0	0	0	0
8603	Mechanical - operation & maintenance management	0	0	0	0	0	0	0
8604	Hydro maintenance of powerhouse & structures	0	0	0	0	0	0	0
8606	Hydro maintenance of dams, waterways and reservoirs	0	0	0	0	0	0	0
8607	Hydro maintenance of other	0	0	0	0	0	0	0
8608	Mechanical - Overhaul hydro unit		0	0	0	0	0	0
8609	Electrical - Overhaul hydro unit		0		0	0	0	0
8618	Mechanical - Maintenance hydro unit		0	0	0	0	0	0
8619	Electrical - Maintenance hydro unit	0	0	0	0	0	0	0
8628	Mechanical - Hydro maintenance of plant auxiliaries		0	0	0	0	0	0
8629	Electrical - Hydro maintenance of plant auxiliaries	0	0	0	0	0	0	0
	Thermal Generation							
8468	Thermal Supervisory Systems	66	37	51	76	158	160	162
8677	System control expense				0	0	0	0
8637	Maintenance planning		0	0	0	0	0	0
8639	Apprentice Positions - Electricians	12	0	0	0	0	0	0
8640	Thermal operation management	591	539	414	383	526	536	542
8642	Thermal generation expense	2,522	2,892	3,058	2,423	2,792	3,139	3,173
8643	Thermal generation maintenance management	271	172	416	368	355	364	368
8644	Maintenance of th. gen. powerhouse, plant & auxiliaries	1,520	2,136	1,837	2,081	2,046	2,090	2,124
8646	Overhaul thermal generation unit							
8647	Maintenance costs for emergency genset units		20	8	25	24	24	25
8648	Mechanical - Overhaul thermal generation unit							
8649	Electrical - Overhaul thermal generation unit							
8657	Thermal generation unit maintenance	2,027	1,794	2,182	2,057	1,979	2,010	2,042
8658	Mechanical - Thermal generation unit maintenance	508	150	48	78	118	121	123
8659	Electrical - Thermal generation unit maintenance		40	76	34	28	29	30
8660	LNG offloading			11	0	0	0	0
8662	Maintenance of LNG plant			48	5	4	4	4
8668	Mechanical - Maint. of th. gen. powerhouse, plant & auxiliaries			3	12	31	32	32
8669	Electrical - Maint. of th. gen. powerhouse, plant & auxiliaries		0	13	33	16	16	16
8673	Transmission line substation structures & equipment			0	0	0	0	0
	Alternative Generation							
8635	Operation and maintenance of alternative energy facilities		7	16	10	9	10	10
	Residual Heat							
8697	Residual heat maintenance	5	46	66	10	10	10	10
	Transmission	0	0	0	0	0	0	0
8870	Transmission line management	0	0	0	0	0	0	0
8871	Transmission line overhead expense	0	0	0	0	0	0	0
8872	Transmission brushing expense	0	0	0	0	0	0	0
8873	Transmission line substation structures and equipment	0	0	0	0	0	0	0
	Distribution	2,021	2,127	1,898	727	1,837	1,863	1,889
8810	T&D - Vehicle operations and maintenance		164	86	50	83	84	86
8811	T&D - Equipment operations and maintenance		35	38	80	60	61	62
8812	T&D lineshop costs		61	59	67	94	95	97
8880	Distribution line management	81	125	14	0	0	0	0
8881	Distribution brushing expense	112	41	37	0	75	77	78
8882	Distribution overhead lines	1,388	1,045	1,083	436	1,263	1,280	1,296
8883	Distribution line underground	0	0	0	0	0	0	0
8884	Distribution customer demand meters	12	5	3	0	0	0	0
8885	Distribution line primary equipment	26	14	10	0	0	0	0
8887	Distribution line streetlights	65	111	33	0	43	43	43
8888	Distribution substation expense	0	0	2	0	0	0	0
8889	Distribution line customer meter reading	280	248	241	85	156	158	159
8890	Apprentice linepersons' training		0	1	0	10	10	10
8892	Trouble Calls	58	277	290	9	54	55	56
	Billing & Customer Accounting	881	211	186	367	327	330	333
8886	Distribution line customer service	881	211	186	367	327	330	333
	General Expense Functions	1,939	1,719	1,526	1,913	1,625	1,654	1,683

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Thermal Zone

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
8480	Hazardous waste disposal	8	53	85	43	38	39	40
8482	Water Testing	0	2		0	0	0	0
8483	Hazardous Materials Cleanup	0	3	0	1	1	1	1
8486	Safety		0	0	0	0	0	0
8487	Environmental	205	94	74	60	36	36	37
8710	OPERATIONS - Vehicle operations and maintenance	374	487	358	408	386	393	400
8711	OPERATIONS - Equipment operations and maintenance	82	18	8	5	0	0	0
8717	Housing O&M Expense	185	252	212	294	320	325	331
8719	Building, yard and fence maint. expense	278	387	371	568	611	621	631
8720	Stores warehouse expense	49	63	62	180	3	3	3
8721	Fuel storage facilities	65	3	0	4	4	4	4
8722	Stockkeeper			0	0	0	0	0
8732	Network Support Operation & Maintenance	692	357	356	350	227	231	236
	Administration Functions	941	883	745	835	696	710	723
8730	Administration O&M	941	883	745	835	696	710	723
	Common Costs	4,082	4,509	5,221	6,453	6,010	6,153	6,240
8138	Distribution related (Billing)	165	40	152	172	172	174	175
8162	Distribution related (CSM maintenance)		18	72	28	38	39	40
8163	Distribution related (Service Desk Management)	74		14	105	92	93	94
8803	Distribution related (Customer service)	228	733	680	944	1,004	1,020	1,031
8880	Distribution line management		4	98	173	191	193	195
8882	Distribution overhead lines	37	85	77	1,198	535	547	555
8890	Apprentice Linepersons' training	4	5	23	31	1	1	1
	Corporate	2,996	3,120	3,242	3,314	3,106	3,194	3,242
	Regional	578	504	863	488	871	892	907
	Grand Total	17,385	17,284	17,826	17,899	18,595	19,257	19,534

Common Cost Allocation Formula

Step 1: [Corp Dist cost] x [Zone's share in corporate retail sales]
Step 2: [Regional dist cost] x [Zone's share in regional retail sales]
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Step 4: [Other regional area cost] x [Zone's share in regional sales]
Step 5: Step 1 + Step 2 + Step 3 + Step 4

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Variance Explanation

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Generation							
	Hydro Generation							
8474	Telecontrol system expense		(55)	(34)	46	(170)	4	4
8475	SCADA control centre expense		(231)	26	(45)	82	3	3
	Cost variance reflects change in budget methodology - this account is now tracked in 8468, 8474, 8475 and corporate costs.							
8600	Electrical - operation & maintenance management		(125)	(28)	32	(49)	2	2
8601	Hydro generation expense		226	(66)	191	(139)	17	12
	Cost variance reflects change in budget methodology - this account is now tracked in 8601 and 8604.							
8602	Hydro camp expenses		272	(8)	65	(56)	10	10
	2014 actual cost variance is due to increased camp contractor costs							
8603	Mechanical - operation & maintenance management		6	90	(87)	9	1	1
8604	Hydro maintenance of powerhouse & structures		(175)	28	(44)	37	4	4
	See explanation for code 8601							
8606	Hydro maintenance of dams, waterways and reservoirs		1	31	(8)	24	2	2
8607	Hydro maintenance of other		3	(63)	29	11	2	2
8608	Mechanical - Overhaul hydro unit		0	(0)	(63)	63	2	2
8609	Electrical - Overhaul hydro unit		(0)	0	0	0	0	0
8618	Mechanical - Maintenance hydro unit		13	132	396	(77)	7	7
	Cost increases due to preventative maintenance and asset management increasing annual shut down inspection costs							
8619	Electrical - Maintenance hydro unit		39	2	48	(125)	2	2
8628	Mechanical - Hydro maintenance of plant auxiliaries		10	6	(0)	12	0	0
8629	Electrical - Hydro maintenance of plant auxiliaries		(7)	60	(5)	(23)	2	2
					0	0	0	0
	Thermal Generation				0	0	0	0
8468	Thermal Supervisory Systems		(30)	22	29	108	3	3
8677	System control expense		0	0	0	0	0	0
8637	Maintenance planning		8	116	27	16	2	2
8639	Apprentice Positions - Electricians		(12)	1	(1)	0	0	0
8640	Thermal operation management		(44)	(287)	(92)	116	12	7
	Cost variance reflects change in budget methodology - this account is now tracked in 8640 and 8643.							
8642	Thermal generation expense		736	606	(216)	(214)	381	48
	Increases from 2013/14 Test Year relate to increased salary & wages for increased plant superintendent wages, step increases, developmental positions and collective agreement impacts. Year over year variances are due to change in generation.							
8643	Thermal generation maintenance management		(110)	286	68	98	12	7
	See explanation for code 8640							
8644	Maintenance of th. gen. powerhouse, plant & auxiliaries		978	(796)	(141)	(63)	48	38
	Change in budget methodology. Costs are now budgeted and tracked between accounts 8644, 8668 and 8669. The aggregate between the three accounts increased due to increased preventative maintenance and asset management costs.							
8646	Overhaul thermal generation unit		0	0	0	0	0	0
8647	Maintenance costs for emergency genset units		20	(12)	17	(1)	0	0
8648	Mechanical - Overhaul thermal generation unit		0	0	0	0	0	0
8649	Electrical - Overhaul thermal generation unit		0	0	0	0	0	0
8657	Thermal generation unit maintenance		(426)	372	(42)	(59)	34	35
	Change in budget methodology between accounts 8657, 8658 and 8659. Aggregate of the three accounts is relatively consistent. Year over year variances are due to changes in thermal							
8658	Mechanical - Thermal generation unit maintenance		(244)	310	(153)	31	13	8
	See explanation for code 8657							
8659	Electrical - Thermal generation unit maintenance		52	227	(215)	(7)	2	2
	See explanation for code 8657							
8660	LNG offloading		0	11	(11)	0	0	0
8662	Maintenance of LNG plant		0	48	(42)	(1)	0	0
8668	Mechanical - Maint. of th. gen. powerhouse, plant & auxiliaries		0	120	275	(5)	8	8
	See explanation for code 8644							
8669	Electrical - Maint. of th. gen. powerhouse, plant & auxiliaries		0	254	62	(33)	14	4
	See explanation for code 8644							
8673	Transmission line substation structures & equipment		0	1	163	126	3	3
	Change in budget methodology - Transferred from account 8873							
	Alternative Generation							
8635	Operation and maintenance of alternative energy facilities		7	9	(6)	(1)	0	0
	Residual Heat							
8697	Residual heat maintenance		41	20	(57)	0	0	0
	Transmission							
8870	Transmission line management		(17)	(4)	(1)	0	0	0

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Account Code and Function - Variance Explanation

Function Codes	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
8871	Transmission line overhead expense		(63)	31	86	(6)	2	2
8872	Transmission brushing expense		(374)	597	(30)	(50)	11	11
	Brushing expenses vary notably from year to year as discussed in previous GRA's.							
8873	Transmission line substation structures and equipment		31	66	(328)	0	0	0
	See explanation for code 8673							
	Distribution							
8810	T&D - Vehicle operations and maintenance		210	(40)	(109)	117	4	4
	Change in budget methodology - Transferred from account 8710							
8811	T&D - Equipment operations and maintenance		59	(5)	101	(45)	2	2
8812	T&D lineshop costs		61	(2)	8	26	2	2
8880	Distribution line management		13	(114)	(15)	0	0	0
8881	Distribution brushing expense		(97)	0	29	75	3	3
8882	Distribution overhead lines		(704)	91	(1,147)	1,296	26	26
	Change in budget methodology - Transferred to Regional costs							
8883	Distribution line underground		(8)	1	(1)	0	0	0
8884	Distribution customer demand meters		(9)	(1)	(6)	0	0	0
8885	Distribution line primary equipment		(20)	(13)	(16)	0	0	0
8887	Distribution line streetlights		39	(79)	(45)	43	0	0
8888	Distribution substation expense		(5)	12	(19)	0	0	0
8889	Distribution line customer meter reading		(34)	(9)	(165)	56	2	2
	Change in budget methodology - Transferred to account 8886							
8890	Apprentice linepersons' training		0	1	(1)	10	0	0
8892	Trouble Calls		290	20	(359)	38	1	1
	Change in budget methodology - Transferred to account 8882							
	Billing & Customer Accounting							
8886	Distribution line customer service		(1,142)	(9)	234	(25)	5	5
	Change in budget methodology - Costs recorded in 8803 and							
	General Expense Functions							
8480	Hazardous waste disposal		37	49	(31)	32	2	2
8482	Water Testing		1	(2)	0	0	0	0
8483	Hazardous Materials Cleanup		4	(4)	2	(1)	0	0
8486	Safety		6	(0)	1	(1)	0	0
8487	Environmental		(202)	(30)	(36)	(8)	1	1
	Change in budget methodology between account 8487 and common costs. Environmental costs are now mainly budgeted in common costs.							
8710	OPERATIONS - Vehicle operations and maintenance		244	(256)	28	(70)	10	10
	2014 actual costs increased due to one time maintenance costs in Inuvik.							
8711	OPERATIONS - Equipment operations and maintenance		(263)	(10)	45	75	4	4
	Change in budget methodology between account 8711 and 8811.							
8717	Housing O&M Expense		69	(67)	93	36	7	7
8719	Building, yard and fence maint. expense		120	12	108	118	15	15
8720	Stores warehouse expense		(54)	(86)	231	(311)	1	1
	Change in budget methodology between account 8720, 8722 and Common Costs							
8721	Fuel storage facilities		(55)	(6)	6	7	0	0
8722	Stockkeeper		0	50	44	31	1	1
8732	Network Support Operation & Maintenance		(90)	(59)	100	(555)	9	10
	Change in budget methodology between account 8732, and common costs.							
	Administration Functions							
8730	Administration O&M		(550)	(55)	(98)	34	53	42
	Change in budget methodology between Regional, account 8730, account 8882 and distributed related common costs							
	Common Costs							
	Corporate		1,096	934	660	(566)	374	234
	Related to incresaes in Health and Safety systems, Human Resource Management, Risk Management, Preventative Maintenance, Asset Management. Please refer to the O&M section of the GRA.							
	Regional		(10)	853	1,294	(645)	64	47
	Change in budget methodology between Regional, account 8730, account 8882 and distributed related common costs							

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - NTPC

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Non-Production Fuel	878	1,127	1,268	1,122	1,194	1,218	1,242
5102	Vehicle Fuel	403	435	310	304	378	385	393
5103	Heating Fuel	94	195	201	161	201	205	209
5104	Lube, Grease, Antifreeze	381	497	756	657	615	627	639
5105	Drum Expense	0						
	Salaries and Wages	13,357	11,774	13,027	12,174	12,722	13,135	13,273
5001	Payroll Regular	8,202	6,376	7,596	7,788	7,739	7,877	7,959
5002	Payroll Overtime	1,366	1,532	1,594	1,040	1,349	1,366	1,383
5003	Casual Payroll Regular	370	643	489	339	434	614	619
5004	Casual Payroll Overtime	70	191	110	40	63	64	64
5005	Fringe Benefits	3,328	2,821	3,070	2,982	3,131	3,208	3,241
5006	Contract Labour	21	0	0	0	0	0	0
5008	Payroll Regular - Educ.Leave	0	0	0	0	0	0	0
5009	Pay Reg Mandatory Training	0	116	139	0	7	7	7
5010	Pay Reg. Discretionary Trainin	0	78	8	0	0	0	0
5011	Pay OT Mandatory Training	0	14	21	0	0	0	0
5012	Pay OT Discretionary Training	0	3	0	0	0	0	0
5930	Overhead Salaries	0	0	0	(15)	0	0	0
	Supplies and Services	8,790	8,394	8,766	9,165	8,928	9,106	9,288
5301	Materials	1,882	1,926	2,169	2,239	1,844	1,881	1,919
5302	Postage & Freight	265	334	305	273	305	311	318
5303	Vehicle & Equipment Rental	124	115	91	156	74	76	77
5304	Inventory Adjustments	0	6	19	0	0	0	0
5305	Inventory Transfers	0	0	0	0	0	0	0
5309	Board Per Diems	0	0	(0)	0	0	0	0
5310	Purchase of Small Tools< $1000	55	74	85	129	113	115	117
5399	P-Card Clearing	0	2	1	0	0	0	0
5401	Office Supplies & Expenses	32	33	43	33	43	44	45
5402	Utilities - Telephone/Fax	576	506	181	167	186	190	194
5403	Building Rental Expense	78	113	131	167	174	177	181
5404	Accommodation Rental Exp	59	135	127	86	126	129	131
5408	Misc.(Customs/Duties/License)	0	6	7	332	2	2	2
5409	Collection and Bad Debts	153	0	0	0	0	0	0
5410	Utility and Rent Recovery	(18)	(14)	(43)	(18)	0	0	0
5411	Equipment & Furniture < $1000	15	28	43	27	26	26	27
5412	Camp Expenses (Incl.Groceries)	357	450	455	478	464	473	482
5413	Cash Over & Short	0	0	0	0	0	0	0
5414	Employee Recognition	11	20	18	33	34	34	35
5415	Satellite Communications	487	364	217	259	430	439	447
5416	Software Licenses	354	285	386	421	1	1	1
5420	Insurance Costs	1,403	1,299	1,291	1,291	1,475	1,505	1,535
5421	Self-insured Costs	0	1	0	0	0	0	0
5430	Grant in lieu of Taxes	244	234	271	251	265	270	275
5431	Business Taxes	1	2	2	0	2	2	2
5432	Licenses	20	42	41	22	20	20	21
5440	Public Relations Costs	24	33	1	4	4	4	4
5441		0	1	0	0	1	1	1
5442	Advertising - General	12	1	0	1	0	0	0
5450	Professional Association Dues	4	0	1	3	2	2	2
5451	Prof. Development Mandatory	28	74	17	1	0	0	0
5452	Prof.Development Discretionary	15	54	23	1	158	161	164
5460	Hire and Transfer Costs	26	105	29	40	0	0	0
5461	Termination Costs	0	20	0	0	0	0	0
5462	Long Service Awards	3	9	1	1	1	1	1
5502	Maintenance Agreements - O&M	38	44	36	30	138	140	143
5504	Consultant&Contractor Services	2,862	2,045	2,788	2,708	3,002	3,062	3,123
5505	Consultant&Contractor Freight	0	1	1	0	1	1	1
5506	Consultant&Contractor Travel	13	29	27	29	38	39	40
5507	Consultant&Contractor Material	18	16	5	1	0	0	0
5508	C & C Mandatory Training	0	0	0	0	0	0	0
5509	C & C Discretionary Training	1	0	0	0	0	0	0
5803	Bank Charges	0	0	0	0	0	0	0
5807	Debt Administration Charges	0	0	0	0	0	0	0
5950	Overhead Supplies	(353)	0	0	0	0	0	0
	Travel and Accommodation	1,407	1,587	1,389	911	1,160	1,294	1,319
5702	Meals	0	0	0	0	0	0	0
5720	Travel	427	397	372	291	313	319	325
5721	Travel Mandatory Training	11	27	14	0	0	0	0
5722	Travel Discretionary Training	8	32	17	2	133	245	250
5723	Air Charter	437	572	553	355	412	420	429

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - NTPC

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
5730	Accommodation	219	187	105	113	87	89	91
5731	Accomm. Mandatory Training	7	13	16	2	0	0	0
5732	Accomm. Discretionary Training	9	21	2	2	75	76	78
5740	Meals & Entertainment	210	151	121	145	94	96	98
5741	Meals - Mandatory Training	6	13	3	0	0	0	0
5742	Meals - Discretionary Training	104	13	1	2	46	47	48
5760	Medical Travel -Transportation	12	109	134	0	0	0	0
5761	Medical Travel - Accommodation	5	28	28	0	0	0	0
5762	Medical Travel - Meals	4	25	21	0	0	0	0
5940	Overhead Travel	(51)	0	0	0	0	0	0
	Common Costs	14,699	15,785	17,572	19,527	18,316	18,753	19,035
	Corporate	13,308	14,405	15,339	15,999	15,433	15,807	16,040
	Regional	1,391	1,381	2,234	3,528	2,883	2,947	2,994
	Grand Total	**39,130**	**38,668**	**42,022**	**42,899**	**42,319**	**43,506**	**44,157**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - Snare

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Non-Production Fuel	223	189	439	297	207	211	216
5102	Vehicle Fuel	201	133	50	95	84	86	88
5103	Heating Fuel	1	27	18	29	26	27	27
5104	Lube, Grease, Antifreeze	21	29	372	173	97	99	101
5105	Drum Expense	0						
	Salaries and Wages	4,205	3,630	4,063	4,330	3,798	3,870	3,909
5001	Payroll Regular	2,714	2,271	2,579	2,925	2,491	2,548	2,574
5002	Payroll Overtime	439	445	476	375	356	360	364
5003	Casual Payroll Regular	36	41	26	35	0	0	0
5004	Casual Payroll Overtime	7	3	16	0	0	0	0
5005	Fringe Benefits	1,010	805	916	1,004	945	955	964
5006	Contract Labour	0			0	0	0	0
5008	Payroll Regular - Educ.Leave	0			0	0	0	0
5009	Pay Reg Mandatory Training	0	41	42	0	7	7	7
5010	Pay Reg. Discretionary Trainin	0	19	6	0	0	0	0
5011	Pay OT Mandatory Training	0	3	4	0	0	0	0
5012	Pay OT Discretionary Training	0	1	0	0	0	0	0
5930	Overhead Salaries	0	0		(9)	0	0	0
	Supplies and Services	3,049	3,160	3,617	3,972	3,816	3,892	3,970
5301	Materials	512	590	877	814	399	407	416
5302	Postage & Freight	29	45	48	31	29	30	30
5303	Vehicle & Equipment Rental	56	36	26	49	21	22	22
5304	Inventory Adjustments	0	(0)	2	0	0	0	0
5305	Inventory Transfers	0			0	0	0	0
5309	Board Per Diems	0	0	0	0	0	0	0
5310	Purchase of Small Tools< $1000	25	24	30	37	23	23	24
5399	P-Card Clearing	0	(1)	1	0	0	0	0
5401	Office Supplies & Expenses	7	16	21	12	16	16	17
5402	Utilities - Telephone/Fax	209	83	29	15	32	33	34
5403	Building Rental Expense	0	0	0	0	0	0	0
5404	Accommodation Rental Exp	4	19	0	0	0	0	0
5408	Misc.(Customs/Duties/License)	0	0	0	328	2	2	2
5409	Collection and Bad Debts	6	0		0	0	0	0
5410	Utility and Rent Recovery	0	0	0	0	0	0	0
5411	Equipment & Furniture < $1000	6	11	18	16	14	14	15
5412	Camp Expenses (Incl.Groceries)	323	422	432	448	439	447	456
5413	Cash Over & Short	0	0		0	0	0	0
5414	Employee Recognition	10	6	7	9	7	7	7
5415	Satellite Communications	80	155	98	137	170	174	177
5416	Software Licenses	165	140	191	174	1	1	1
5420	Insurance Costs	843	793	789	785	898	916	934
5421	Self-insured Costs	0	0		0	0	0	0
5430	Grant in lieu of Taxes	129	139	158	138	227	232	236
5431	Business Taxes	1	2	2	0	2	2	2
5432	Licenses	12	20	13	10	8	8	8
5440	Public Relations Costs	8	0	1	0	0	0	0
5441					0	0	0	0
5442	Advertising - General	10	1	0	0	0	0	0
5450	Professional Association Dues	4	0	1	3	2	2	2
5451	Prof. Development Mandatory	22	29	3	1	0	0	0
5452	Prof.Development Discretionary	14	24	3	1	85	87	89
5460	Hire and Transfer Costs	18	29	8	15	0	0	0
5461	Termination Costs	0	20	0	0	0	0	0
5462	Long Service Awards	3	0	0	0	0	0	0
5502	Maintenance Agreements - O&M	12	29	18	17	94	96	98
5504	Consultant&Contractor Services	875	526	836	926	1,346	1,373	1,400
5505	Consultant&Contractor Freight	0	0	0	0	0	0	0
5506	Consultant&Contractor Travel	10	0	2	3	0	0	0
5507	Consultant&Contractor Material	8	0	0	0	0	0	0
5508	C & C Mandatory Training	0	0		0	0	0	0
5509	C & C Discretionary Training	0	0		0	0	0	0
5803	Bank Charges	0			0	0	0	0
5807	Debt Administration Charges	0			0	0	0	0
5950	Overhead Supplies	(353)	0		0	0	0	0
	Travel and Accommodation	252	397	349	250	324	330	337
5702	Meals	0						
5720	Travel	86	67	49	19	23	23	23
5721	Travel Mandatory Training	3	0	0	0	0	0	0
5722	Travel Discretionary Training	4	2	1	2	28	28	29
5723	Air Charter	137	264	259	201	225	229	234

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - Snare

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
5730	Accommodation	36	28	12	6	6	6	6
5731	Accomm. Mandatory Training	2	0	0	2	0	0	0
5732	Accomm. Discretionary Training	5	4	1	2	19	20	20
5740	Meals & Entertainment	18	20	20	17	11	11	12
5741	Meals - Mandatory Training	2	0	0	0	0	0	0
5742	Meals - Discretionary Training	2	2	1	2	13	14	14
5760	Medical Travel -Transportation	5	6	5	0	0	0	0
5761	Medical Travel - Accommodation	2	2	1	0	0	0	0
5762	Medical Travel - Meals	2	2	1	0	0	0	0
5940	Overhead Travel	(51)	0		0	0	0	0
	Common Costs	7,945	8,224	9,030	9,195	8,825	9,038	9,176
	Corporate	7,415	7,762	8,289	8,434	8,057	8,253	8,377
	Regional	529	462	741	761	768	784	799
	Grand Total	**15,673**	**15,599**	**17,498**	**18,043**	**16,970**	**17,341**	**17,608**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - Taltson

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Non-Production Fuel	51	45	47	64	60	61	63
5102	Vehicle Fuel	25	32	26	31	41	41	42
5103	Heating Fuel	2	8	7	8	8	8	8
5104	Lube, Grease, Antifreeze	24	5	14	26	12	12	12
5105	Drum Expense	0						
	Salaries and Wages	1,861	1,571	1,684	1,492	1,656	1,691	1,710
5001	Payroll Regular	1,206	926	1,039	944	1,028	1,044	1,055
5002	Payroll Overtime	154	198	237	124	162	165	168
5003	Casual Payroll Regular	17	26	20	28	59	68	68
5004	Casual Payroll Overtime	1	8	6	0	6	7	7
5005	Fringe Benefits	464	366	364	396	401	407	412
5006	Contract Labour	21			0	0	0	0
5008	Payroll Regular - Educ.Leave	0			0	0	0	0
5009	Pay Reg Mandatory Training	0	37	17	0	0	0	0
5010	Pay Reg. Discretionary Trainin	0	0	0	0	0	0	0
5011	Pay OT Mandatory Training	0	9	2	0	0	0	0
5012	Pay OT Discretionary Training	0	0	0	0	0	0	0
5930	Overhead Salaries	0	0		0	0	0	0
	Supplies and Services	1,295	943	1,437	1,445	1,439	1,468	1,497
5301	Materials	230	185	223	232	352	359	366
5302	Postage & Freight	28	25	24	32	55	56	57
5303	Vehicle & Equipment Rental	15	10	11	5	5	5	5
5304	Inventory Adjustments	0	0	0	0	0	0	0
5305	Inventory Transfers	0			0	0	0	0
5309	Board Per Diems	0	0	(0)	0	0	0	0
5310	Purchase of Small Tools< $1000	6	4	10	7	14	14	15
5399	P-Card Clearing	0	(0)	0	0	0	0	0
5401	Office Supplies & Expenses	1	3	4	2	4	4	4
5402	Utilities - Telephone/Fax	144	144	39	52	55	56	57
5403	Building Rental Expense	0	0	5	0	0	0	0
5404	Accommodation Rental Exp	3	15	24	3	14	14	15
5408	Misc.(Customs/Duties/License)	0	0	0	0	1	1	1
5409	Collection and Bad Debts	20	0		0	0	0	0
5410	Utility and Rent Recovery	0	0	0	0	0	0	0
5411	Equipment & Furniture < $1000	1	1	1	0	0	0	0
5412	Camp Expenses (Incl.Groceries)	34	28	22	30	25	26	26
5413	Cash Over & Short	0	0		0	0	0	0
5414	Employee Recognition	1	1	1	6	7	7	7
5415	Satellite Communications	60	31	30	22	55	56	58
5416	Software Licenses	48	30	41	52	0	0	0
5420	Insurance Costs	196	176	173	172	197	201	205
5421	Self-insured Costs	0	0		0	0	0	0
5430	Grant in lieu of Taxes	21	16	17	17	17	17	18
5431	Business Taxes	0	0	0	0	0	0	0
5432	Licenses	5	6	14	4	6	6	6
5440	Public Relations Costs	16	28	0	0	0	0	0
5441			0	0	0	0	0	0
5442	Advertising - General	1	1	0	1	0	0	0
5450	Professional Association Dues	0	0	0	0	0	0	0
5451	Prof. Development Mandatory	6	13	0	0	0	0	0
5452	Prof.Development Discretionary	1	11	6	0	30	31	31
5460	Hire and Transfer Costs	8	0	2	0	0	0	0
5461	Termination Costs	0	0	0	0	0	0	0
5462	Long Service Awards	0	0	0	0	0	0	0
5502	Maintenance Agreements - O&M	1	10	15	5	5	5	5
5504	Consultant&Contractor Services	437	206	775	804	591	602	614
5505	Consultant&Contractor Freight	0	0	0	0	0	0	0
5506	Consultant&Contractor Travel	1	0	0	0	9	9	9
5507	Consultant&Contractor Material	9	(0)	0	0	0	0	0
5508	C & C Mandatory Training	0	0		0	0	0	0
5509	C & C Discretionary Training	0	0		0	0	0	0
5803	Bank Charges	0			0	0	0	0
5807	Debt Administration Charges	0			0	0	0	0
5950	Overhead Supplies	0	0		0	0	0	0
	Travel and Accommodation	193	174	207	77	117	125	127
5702	Meals	0			0			
5720	Travel	51	40	21	9	16	16	16
5721	Travel Mandatory Training	3	5	1	0	0	0	0
5722	Travel Discretionary Training	2	2	0	0	14	19	20
5723	Air Charter	48	66	143	48	58	60	61

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - Taltson

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
5730	Accommodation	39	11	14	7	2	2	2
5731	Accomm. Mandatory Training	2	5	1	0	0	0	0
5732	Accomm. Discretionary Training	1	1	0	0	8	8	8
5740	Meals & Entertainment	32	14	15	14	14	14	14
5741	Meals - Mandatory Training	3	6	1	0	0	0	0
5742	Meals - Discretionary Training	1	0	0	0	5	6	6
5760	Medical Travel -Transportation	7	19	5	0	0	0	0
5761	Medical Travel - Accommodation	3	2	3	0	0	0	0
5762	Medical Travel - Meals	2	2	2	0	0	0	0
5940	Overhead Travel	0	0		0	0	0	0
	Common Costs	2,672	3,053	3,321	3,879	3,481	3,563	3,618
	Corporate	2,430	2,731	2,889	3,002	2,963	3,034	3,081
	Regional	242	322	432	877	518	529	537
	Grand Total	**6,072**	**5,785**	**6,697**	**6,957**	**6,754**	**6,908**	**7,015**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - Thermal

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Non-Production Fuel	603	893	781	760	926	945	964
5102	Vehicle Fuel	176	270	234	178	253	258	263
5103	Heating Fuel	91	160	177	124	167	171	174
5104	Lube, Grease, Antifreeze	336	463	370	458	506	516	526
5105	Drum Expense	0						
	Salaries and Wages	7,291	6,573	7,280	6,352	7,267	7,575	7,654
5001	Payroll Regular	4,283	3,179	3,979	3,919	4,221	4,285	4,330
5002	Payroll Overtime	773	889	882	541	830	841	851
5003	Casual Payroll Regular	317	576	443	277	375	547	550
5004	Casual Payroll Overtime	63	179	89	40	56	57	58
5005	Fringe Benefits	1,855	1,649	1,790	1,581	1,785	1,846	1,864
5006	Contract Labour	0			0	0	0	0
5008	Payroll Regular - Educ.Leave	0			0	0	0	0
5009	Pay Reg Mandatory Training	0	38	80	0	0	0	0
5010	Pay Reg. Discretionary Trainin	0	59	1	0	0	0	0
5011	Pay OT Mandatory Training	0	3	15	0	0	0	0
5012	Pay OT Discretionary Training	0	2	0	0	0	0	0
5930	Overhead Salaries	0	0		(6)	0	0	0
	Supplies and Services	4,446	4,292	3,711	3,749	3,673	3,746	3,821
5301	Materials	1,140	1,152	1,069	1,193	1,093	1,115	1,137
5302	Postage & Freight	208	264	232	209	222	226	231
5303	Vehicle & Equipment Rental	52	69	54	102	48	49	50
5304	Inventory Adjustments	0	7	17	0	0	0	0
5305	Inventory Transfers	0			0	0	0	0
5309	Board Per Diems	0	0	0	0	0	0	0
5310	Purchase of Small Tools< $1000	24	46	45	85	76	77	79
5399	P-Card Clearing	0	3	0	0	0	0	0
5401	Office Supplies & Expenses	24	14	19	19	23	24	24
5402	Utilities - Telephone/Fax	223	278	113	101	99	101	103
5403	Building Rental Expense	78	113	126	167	174	177	181
5404	Accommodation Rental Exp	51	101	102	83	112	115	117
5408	Misc.(Customs/Duties/License)	0	5	7	4	0	0	0
5409	Collection and Bad Debts	128	0		0	0	0	0
5410	Utility and Rent Recovery	(18)	(14)	(43)	(18)	0	0	0
5411	Equipment & Furniture < $1000	9	16	24	11	12	12	12
5412	Camp Expenses (Incl.Groceries)	0	0	(0)	0	0	0	0
5413	Cash Over & Short	0	0		0	0	0	0
5414	Employee Recognition	0	13	10	18	20	20	21
5415	Satellite Communications	347	178	89	101	204	208	213
5416	Software Licenses	141	114	154	195	0	0	0
5420	Insurance Costs	363	330	329	333	381	389	397
5421	Self-insured Costs	0	1		0	0	0	0
5430	Grant in lieu of Taxes	94	80	95	96	20	21	21
5431	Business Taxes	0	0	0	0	0	0	0
5432	Licenses	2	16	14	7	6	7	7
5440	Public Relations Costs	0	5	0	4	4	4	4
5441	Corporate Donations		1	0	0	1	1	1
5442	Advertising - General	1	0	0	0	0	0	0
5450	Professional Association Dues	0	0	0	0	0	0	0
5451	Prof. Development Mandatory	1	32	13	0	0	0	0
5452	Prof.Development Discretionary	(0)	19	14	0	42	43	44
5460	Hire and Transfer Costs	0	76	19	25	0	0	0
5461	Termination Costs	0	0	0	0	0	0	0
5462	Long Service Awards	0	9	1	1	1	1	1
5502	Maintenance Agreements - O&M	25	6	2	8	39	40	40
5504	Consultant&Contractor Services	1,549	1,313	1,176	977	1,065	1,086	1,108
5505	Consultant&Contractor Freight	0	1	1	0	1	1	1
5506	Consultant&Contractor Travel	2	29	24	26	29	30	30
5507	Consultant&Contractor Material	1	16	5	1	0	0	0
5508	C & C Mandatory Training	0	0		0	0	0	0
5509	C & C Discretionary Training	1	0		0	0	0	0
5803	Bank Charges	0			0	0	0	0
5807	Debt Administration Charges	0			0	0	0	0
5950	Overhead Supplies	0	0		0	0	0	0
	Travel and Accommodation	962	1,017	833	585	719	838	855
5702	Meals	0						
5720	Travel	289	291	302	264	274	280	286
5721	Travel Mandatory Training	5	22	13	0	0	0	0
5722	Travel Discretionary Training	2	29	16	0	91	198	202
5723	Air Charter	252	241	152	107	129	132	134

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
O&M Expense by Resource - Thermal

Account	Descriptions	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
5730	Accommodation	144	148	79	100	80	82	83
5731	Accomm. Mandatory Training	3	8	15	0	0	0	0
5732	Accomm. Discretionary Training	4	15	1	0	48	49	50
5740	Meals & Entertainment	160	117	86	114	69	71	72
5741	Meals - Mandatory Training	2	6	1	0	0	0	0
5742	Meals - Discretionary Training	102	10	0	0	28	28	29
5760	Medical Travel -Transportation	0	84	123	0	0	0	0
5761	Medical Travel - Accommodation	0	24	24	0	0	0	0
5762	Medical Travel - Meals	0	21	19	0	0	0	0
5940	Overhead Travel	0	0		0	0	0	0
	Common Costs	4,082	4,509	5,221	6,453	6,010	6,153	6,240
	Head Office	3,463	3,911	4,161	4,563	4,413	4,519	4,582
	Regional	619	598	1,061	1,890	1,597	1,633	1,658
	Grand Total	**17,385**	**17,284**	**17,826**	**17,899**	**18,595**	**19,257**	**19,534**

CHAPTER 6

AMORTIZATION EXPENSE

6.0 AMORTIZATION EXPENSE

Amortization expense in the Test Years includes fixed asset amortization, true-up and amortization of deferred charges. Variance explanations for amortization of deferred charges can be found in Section 11.4. NTPC's amortization expense compared to the 2013/14 Test Year is shown in Table 6.1.

Table 6.1
Amortization Expense – 2013/14 Test Year
Compared to 2016/17 – 2018/19 Forecasts (000's)

		Test Year		
	2013/14 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Fixed Asset Amortization (less Customer Contributions)	12,631	15,120	16,146	17,005
True Up	1,839	1,288	1,288	1,288
Amortization of Deferred Charges	5,348	7,865	7,977	7,809
	19,817	24,273	25,412	26,102

6.1 FIXED ASSET AMORTIZATION

The costs for amortization of fixed assets for the 2018/19 Test Year is $3.8 million higher than for 2013/14 as shown in Table 6.2.

Table 6.2

Amortization Expense – Change from 2013/14 Test Year to 2018/19 Test Year ($000's)

	Fixed Asset Amortization
2013/14 Test Year	14,470
Gross Plant Additions	3,480
Increased Amortization Rates	305
Negative Salvage Collection	658
True-up Provision Change	(551)
Customer Contribution Amortization	(69)
2018/19 Forecast	18,293

Note: 2013/14 forecast reflects adjustment for Inuvik LNG Storage and Gasification Facility Commissioning.

From the 2013/14 Test Year to the 2018/19 Test Year, end of year gross plant increased by 21% ($98 million) to $559 million. Increases in gross plant account for 91% of the change in fixed asset amortization expense. Please refer to Schedule 11.1 and Section 11.2 for additions to plant.

6.2 AMORTIZATION STUDY

The Corporation completed an amortization study for electric plant-in-service as at March 31, 2015. The Corporation completed an amortization study for the 2012/14 GRA for electric plant-in-service as at March 31, 2011. As with prior NTPC amortization studies, the work was performed by Gannett Fleming and their report, setting forth the results of the study, is included in Chapter 14 of this Application.

The amortization study consisted of two phases: (1) the estimation of survivor curves and net salvage percent for each depreciable group and (2) the calculation of annual and accrued amortization as of March 31, 2015. The estimation of survivor curves involves a consideration of statistical analyses of historical retirements, discussions with management regarding current plans and operating policies, consideration of current developments in the electric industry and a general knowledge of the life and salvage characteristics of other electric properties.

6.3 AMORTIZATION STUDY IMPLEMENTATION

NTPC is proposing to implement the study for the 2016/17 Test Year. For the 2012/14 GRA the Corporation delayed the implementation of the study until the second Test Year. NTPC proposed to implement the study in the second Test Year due to the length of time between studies (the previous study was conducted as of March 31, 2000.) NTPC felt it was prudent to delay the study until a full regulatory review could be conducted. Those considerations are not applicable for the current study.

As part of the study the calculation of accrued amortization is compared to book value accumulated amortization for both life and net salvage. For the 2011 study, the life variance for accumulated amortization was a shortfall of approximately $38 million and a surplus on net salvage of approximately $20 million. For the 2012/14 GRA, the Board approved a “pause” on the collection of net salvage to gradually permit the surplus to decrease over time. The Board approved a collection or “true-up” on the shortfall variance of life accumulated amortization of approximately $1.8 million per year. As per their 2016 study, Gannett Fleming remains of the view that net salvage is an important

component of amortization rates. When developing the 2016 amortization study, it was apparent there would be a significant increase in recommended net salvage rates developed by Gannett Fleming that would increase total amortization expense. The Corporation also feels net salvage is an integral component of amortization rates and to balance increasing energy rates with the recommended net salvage rates, the Corporation asked Gannett Fleming to calculate a “phase-in” for the reimplementation of net salvage accruals.

From the results of the 2016 study, the life shortfall has decreased to $22.7 million from changes in amortization rates and the Board’s approval of the true-up provision. The net salvage surplus using the recommended salvage rates is $6.3 million resulting from increases in salvage rates and the Board’s approval of the pause approach on the collection of salvage.

The weighted average life amortization rate remains constant at approximately 3% from the last study; However, individual life amortization rates by FERC class have changed since the 2011 study; as has the asset mix resulting in the $0.305 million increase in amortization rates. The true-up for life amortization reduces amortization expense from $1.8 million to $1.228 million as the life variance has decreased from $38 million to $22.7 million. The Corporation is proposing to turn net salvage rates back on, albeit through a phased approach recognizing cost pressures faced by customers. As a result of the phased in approach, the impact on amortization expense is a reduction of approximately $2 million from the recommended net salvage rates. Gannett Fleming’s analysis indicates NTPC is presently in a $6 million surplus position with respect to net

salvage. The study also indicates although there is a surplus in net salvage, there should be a true-up on net salvage of $0.150 million per year. This is a result of FERC accounts with a shorter remaining life being in a shortfall position. The Corporation is proposing not to collect the true up for net salvage due to the surplus position.

Schedule 6.0

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Plant Amortization Expense

Line No.	Description	Cross Ref.	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
1	Fixed Asset Amortization	S. 6.1	13,239	12,529	13,254	13,925	15,797	16,823	17,682
2	True-up Provision	S. 6.2.1-6.2.3	1,839	1,839	1,839	1,839	1,288	1,288	1,288
3	Amortization of Deferred Charges	S.11.4 & 11.5	5,348	5,587	5,639	5,708	7,865	7,977	7,809
4	Customer Contribution Amortization	S. 11.3	(608)	(631)	(616)	(647)	(677)	(677)	(677)
5	Total Depreciation Expense	S.3.0 L.12	19,817	19,324	20,115	20,825	24,273	25,412	26,102

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2016/17 Amortization Expense ($000)

FERC	DESCRIPTION	2016/17 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	Solar Photovoltaic Assets	3,655	-	3,655	4.00%	146	1,721	34	181	5
121	Wind	353	363	(10)	2.75%	(0)	-	-	(0)	(19)
131	Heat Recovery Systems	5,656	-	5,656	3.57%	202	(0)	(0)	202	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	4,109	-	4,109	0.00%	-	-	-	-	-
331	Structures & Improvements	16,049	72	15,978	1.05%	168	247	1	169	(16)
332	Resv., Dams & Waterways	65,083	-	65,083	1.05%	683	486	3	686	45
333	Turbines and Generators	22,464	1,584	20,880	2.10%	438	11,775	124	562	106
334	Accessory Electric Equip.	18,706	24	18,682	2.63%	491	111	1	493	(56)
335	Misc. Power Plant Equip.	2,807	371	2,436	5.25%	128	190	5	133	(40)
336	Roads & Bridges	10,796	-	10,796	2.10%	227	-	-	227	91
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	-
331	Structures & Improvements	6,576	-	6,576	1.05%	69	-	-	69	-
332	Resv., Dams & Waterways	6,110	-	6,110	1.05%	64	-	-	64	-
333	Turbines and Generators	9,891	-	9,891	2.10%	208	-	-	208	-
334	Accessory Electric Equip.	2,591	-	2,591	2.63%	68	-	-	68	-
335	Misc. Power Plant Equip.	735	-	735	5.25%	39	-	-	39	-
336	Roads & Bridges	439	-	439	2.10%	9	-	-	9	-
1722 & 1732 DIESEL										
340	Land and Land Rights	1,104	32	1,072	0.00%	-	-	-	-	-
341	Structures & Improvements	49,041	191	48,850	3.37%	1,646	1,299	22	1,668	286
342	Fuel Holders, Prod., & Access.	24,560	-	24,560	3.66%	899	1,129	21	920	80
343	Prime Movers	62,992	1,978	61,014	4.58%	2,794	6,328	145	2,939	270
344	Generators	8,240	5	8,234	3.75%	309	(19)	(0)	308	16
345	Accessory Electric Equip.	25,810	30	25,781	4.38%	1,129	1,051	23	1,152	-
346	Misc. Power Plant Equip.	1,963	-	1,963	4.55%	89	41	1	90	(32)
348	Energy Storage Equipment - Prod	-	-		4.00%	-	-	-	-	-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	5	-	5	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	3,122	-	3,122	1.54%	48	-	-	48	11
352	Structures & Improvements	3,801	-	3,801	2.50%	95	-	-	95	8
353	Station Equipment	17,377	200	17,177	3.62%	622	438	8	630	-
354	Towers & Fixtures	15,400	9	15,391	1.62%	249	(0)	(0)	249	142
355	Poles & Fixtures	1,770	-	1,770	2.33%	41	-	-	41	7
356	OH Conductors & Devices	10,797	9	10,788	1.75%	189	1,528	13	202	47
357	Underground Conduit	12	-	12	3.33%	0	-	-	0	(0)
358	Underground Conduct. & Dev.	16	-	16	3.33%	1	-	-	1	(0)
359	Roads & Trails	1,010	-	1,010	2.50%	25	-	-	25	(11)
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	339	-	339	0.00%	-	-	-	-	-
361	Structures & Improvements	830	-	830	2.50%	21	-	-	21	5
362	Station Equipment	2,109	-	2,109	4.00%	84	49	1	85	13
363	Storage Battery Equip.	62	-	62	6.67%	4	-	-	4	(30)
364	Poles & Fixtures	15,214	37	15,177	2.10%	319	(27)	(0)	318	(35)
365	OH Conductors & Devices	4,414	6	4,408	1.91%	84	902	9	93	(9)
366	Underground Conduit	129	-	129	3.33%	4	-	-	4	1
367	Undergrd Conduct. & Devices	684	-	684	3.33%	23	-	-	23	7
368	Line Transformers	6,506	16	6,490	2.00%	130	(42)	(0)	129	(25)
369	Services	2,460	20	2,440	1.91%	47	(7)	(0)	47	(3)
370	Meters	1,475	-	1,475	5.56%	82	619	17	99	21
371	Install. on Cust. Premises	11	-	11	5.56%	1	-	-	1	2
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	2,155	-	2,155	2.18%	47	(2)	(0)	47	0
1725 & 1735 GENERAL										
389	Land and Land Rights	303	-	303	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	10,724	2	10,722	3.77%	404	(161)	(3)	401	(261)
382	Computers	3,232	-	3,232	20.00%	646	(424)	(42)	604	273
391.2	Office Furniture & Equip.	182	-	182	6.00%	11	(44)	(1)	10	(10)
383	Software	163	-	163	10.00%	16	8	0	17	2
	Office Furniture & Equip. - G/L	-	-	-	0.00%	-	-	-	-	118
392	Transportation Equip.	3,181	177	3,004	11.31%	340	(62)	(4)	336	-
393	Stores Equip.	110	-	110	6.67%	7	-	-	7	3
394	Tools, Shop, & Garage Equip.	449	13	436	6.67%	29	(3)	(0)	29	(6)
395	Laboratory Equip.	167	-	167	4.00%	7	-	-	7	-
396	Power Operated Equip.	5,279	-	5,279	3.14%	166	(9)	(0)	166	(38)
397	Communication Equip.	6,113	-	6,113	4.47%	273	428	10	283	(12)
398	Misc. Equip.	402	-	402	6.67%	27	-	-	27	(7)
399	Other Tangible Property	351	-	351	5.00%	18	-	-	18	1
	Capital Inventory	-	-	-	0.00%	-	-	-	-	-
	Insurance Proceeds	(13,139)	-	(13,139)		(292)	-	-	(292)	-
	Subtotal Zone Specific	456,947	5,140	451,806		13,575	27,550	386	13,961	951
	Common Cost									
	Corporate								1,513	340
	Regional								303	(3)
	Distribution Related								19	-
	Subtotal Common Cost								1,836	337
	Total	456,947	5,140	451,806		13,575	27,550	386	15,797	1,288

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2017/18 Amortization Expense ($000)

FERC	DESCRIPTION	2017/18 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	Solar Photovoltaic Assets	5,376	-	5,376	4.00%	215	-	-	215	5
121	Wind	353	363	(10)	2.75%	(0)	-	-	(0)	(19)
131	Heat Recovery Systems	5,656	-	5,656	3.57%	202	(0)	(0)	202	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	4,109	-	4,109	0.00%	-	-	-	-	-
331	Structures & Improvements	16,296	72	16,224	1.05%	170	(1)	(0)	170	(16)
332	Resv., Dams & Waterways	65,569	-	65,569	1.05%	688	(11)	(0)	688	45
333	Turbines and Generators	34,239	1,584	32,655	2.10%	686	70	1	686	106
334	Accessory Electric Equip.	18,817	24	18,793	2.63%	494	92	1	495	(56)
335	Misc. Power Plant Equip.	2,997	371	2,626	5.25%	138	1,132	30	168	(40)
336	Roads & Bridges	10,796	-	10,796	2.10%	227	40	0	227	91
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	-
331	Structures & Improvements	6,576	-	6,576	1.05%	69	-	-	69	-
332	Resv., Dams & Waterways	6,110	-	6,110	1.05%	64	-	-	64	-
333	Turbines and Generators	9,891	-	9,891	2.10%	208	-	-	208	-
334	Accessory Electric Equip.	2,591	-	2,591	2.63%	68	-	-	68	-
335	Misc. Power Plant Equip.	735	-	735	5.25%	39	-	-	39	-
336	Roads & Bridges	439	-	439	2.10%	9	-	-	9	-
1722 & 1732 DIESEL										
340	Land and Land Rights	1,104	32	1,072	0.00%	-	-	-	-	-
341	Structures & Improvements	50,340	191	50,149	3.37%	1,690	3,292	55	1,745	286
342	Fuel Holders, Prod., & Access.	25,689	-	25,689	3.66%	940	1,348	25	965	80
343	Prime Movers	69,320	1,978	67,343	4.58%	3,084	1,026	24	3,108	270
344	Generators	8,221	5	8,216	3.75%	308	(9)	(0)	308	16
345	Accessory Electric Equip.	26,861	30	26,832	4.38%	1,175	3,610	79	1,254	-
346	Misc. Power Plant Equip.	2,004	-	2,004	4.55%	91	75	2	93	(32)
348	Energy Storage Equipment - Prod	-	-		4.00%	-	-	-	-	-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	5	-	5	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	3,122	-	3,122	1.54%	48	-	-	48	11
352	Structures & Improvements	3,801	-	3,801	2.50%	95	-	-	95	8
353	Station Equipment	17,815	200	17,615	3.62%	638	790	14	652	-
354	Towers & Fixtures	15,400	9	15,391	1.62%	249	(0)	(0)	249	142
355	Poles & Fixtures	1,770	-	1,770	2.33%	41	150	2	43	7
356	OH Conductors & Devices	12,325	9	12,316	1.75%	216	150	1	217	47
357	Underground Conduit	12	-	12	3.33%	0	-	-	0	(0)
358	Underground Conduct. & Dev.	16	-	16	3.33%	1	-	-	1	(0)
359	Roads & Trails	1,010	-	1,010	2.50%	25	-	-	25	(11)
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	339	-	339	0.00%	-	-	-	-	-
361	Structures & Improvements	830	-	830	2.50%	21	-	-	21	5
362	Station Equipment	2,158	-	2,158	4.00%	86	531	11	97	13
363	Storage Battery Equip.	62	-	62	6.67%	4	161	5	10	(30)
364	Poles & Fixtures	15,187	37	15,150	2.10%	318	(13)	(0)	318	(35)
365	OH Conductors & Devices	5,316	6	5,310	1.91%	101	349	3	105	(9)
366	Underground Conduit	129	-	129	3.33%	4	-	-	4	1
367	Undergrd Conduct. & Devices	684	-	684	3.33%	23	-	-	23	7
368	Line Transformers	6,465	16	6,448	2.00%	129	(20)	(0)	129	(25)
369	Services	2,453	20	2,432	1.91%	46	(4)	(0)	46	(3)
370	Meters	2,094	-	2,094	5.56%	116	(90)	(3)	114	21
371	Install. on Cust. Premises	11	-	11	5.56%	1	-	-	1	2
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	2,152	-	2,152	2.18%	47	(3)	(0)	47	0
1725 & 1735 GENERAL										
389	Land and Land Rights	303	-	303	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	10,563	2	10,561	3.77%	398	336	6	404	(261)
382	Computers	2,808	-	2,808	20.00%	562	(192)	(19)	542	273
391.2	Office Furniture & Equip.	138	-	138	6.00%	8	(19)	(1)	8	(10)
383	Software	171	-	171	10.00%	17	-	-	17	2
	Office Furniture & Equip. - G/L	-	-	-	0.00%	-	-	-	-	118
392	Transportation Equip.	3,119	177	2,942	11.31%	333	(63)	(4)	329	-
393	Stores Equip.	110	-	110	6.67%	7	-	-	7	3
394	Tools, Shop, & Garage Equip.	446	13	433	6.67%	29	(1)	(0)	29	(6)
395	Laboratory Equip.	167	-	167	4.00%	7	-	-	7	-
396	Power Operated Equip.	5,270	-	5,270	3.14%	165	(4)	(0)	165	(38)
397	Communication Equip.	6,541	-	6,541	4.47%	292	410	9	302	(12)
398	Misc. Equip.	402	-	402	6.67%	27	-	-	27	(7)
399	Other Tangible Property	351	-	351	5.00%	18	-	-	18	1
	Capital Inventory	-	-	-	0.00%	-	-	-	-	-
	Insurance Proceeds	(13,139)	-	(13,139)		(292)	-	-	(292)	-
	Subtotal Zone Specific	484,497	5,140	479,357		14,348	13,131	242	14,590	951
	Common Cost									
	Corporate								1,711	340
	Regional								472	(3)
	Distribution Related								51	-
	Subtotal Common Cost								2,234	337
	Total	484,497	5,140	479,357		14,348	13,131	242	16,823	1,288

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2018/19 Amortization Expense ($000)

FERC	DESCRIPTION	2018/19 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	Solar Photovoltaic Assets	5,376	-	5,376	4.00%	215	-	-	215	5
121	Wind	353	363	(10)	2.75%	(0)	-	-	(0)	(19)
131	Heat Recovery Systems	5,656	-	5,656	3.57%	202	(0)	(0)	202	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	4,109	-	4,109	0.00%	-	-	-	-	-
331	Structures & Improvements	16,295	72	16,223	1.05%	170	117	1	171	(16)
332	Resv., Dams & Waterways	65,558	-	65,558	1.05%	688	(25)	(0)	688	45
333	Turbines and Generators	34,309	1,584	32,725	2.10%	687	7,862	83	770	106
334	Accessory Electric Equip.	18,908	24	18,885	2.63%	497	(8)	(0)	497	(56)
335	Misc. Power Plant Equip.	4,129	371	3,758	5.25%	197	453	12	209	(40)
336	Roads & Bridges	10,836	-	10,836	2.10%	228	-	-	228	91
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	-
331	Structures & Improvements	6,576	-	6,576	1.05%	69	-	-	69	-
332	Resv., Dams & Waterways	6,110	-	6,110	1.05%	64	-	-	64	-
333	Turbines and Generators	9,891	-	9,891	2.10%	208	-	-	208	-
334	Accessory Electric Equip.	2,591	-	2,591	2.63%	68	-	-	68	-
335	Misc. Power Plant Equip.	735	-	735	5.25%	39	-	-	39	-
336	Roads & Bridges	439	-	439	2.10%	9	-	-	9	-
1722 & 1732 DIESEL										
340	Land and Land Rights	1,104	32	1,072	0.00%	-	-	-	-	-
341	Structures & Improvements	53,632	191	53,440	3.37%	1,801	4,916	83	1,884	286
342	Fuel Holders, Prod., & Access.	27,037	-	27,037	3.66%	990	515	9	999	80
343	Prime Movers	70,346	1,978	68,369	4.58%	3,131	1,619	37	3,168	270
344	Generators	8,212	5	8,207	3.75%	308	(13)	(0)	308	16
345	Accessory Electric Equip.	30,471	30	30,441	4.38%	1,333	527	12	1,345	-
346	Misc. Power Plant Equip.	2,079	-	2,079	4.55%	95	75	2	96	(32)
348	Energy Storage Equipment - Prod	-	-		4.00%	-	-	-	-	-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	5	-	5	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	3,122	-	3,122	1.54%	48	-	-	48	11
352	Structures & Improvements	3,801	-	3,801	2.50%	95	1,229	15	110	8
353	Station Equipment	18,605	200	18,405	3.62%	666	967	18	684	-
354	Towers & Fixtures	15,400	9	15,391	1.62%	249	(0)	(0)	249	142
355	Poles & Fixtures	1,920	-	1,920	2.33%	45	150	2	46	7
356	OH Conductors & Devices	12,475	9	12,466	1.75%	218	-	-	218	47
357	Underground Conduit	12	-	12	3.33%	0	-	-	0	(0)
358	Underground Conduct. & Dev.	16	-	16	3.33%	1	-	-	1	(0)
359	Roads & Trails	1,010	-	1,010	2.50%	25	-	-	25	(11)
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	339	-	339	0.00%	-	-	-	-	-
361	Structures & Improvements	830	-	830	2.50%	21	-	-	21	5
362	Station Equipment	2,689	-	2,689	4.00%	108	425	9	116	13
363	Storage Battery Equip.	223	-	223	6.67%	15	-	-	15	(30)
364	Poles & Fixtures	15,174	37	15,137	2.10%	318	(19)	(0)	318	(35)
365	OH Conductors & Devices	5,666	6	5,659	1.91%	108	149	1	110	(9)
366	Underground Conduit	129	-	129	3.33%	4	-	-	4	1
367	Undergrd Conduct. & Devices	684	-	684	3.33%	23	-	-	23	7
368	Line Transformers	6,445	16	6,428	2.00%	129	(30)	(0)	128	(25)
369	Services	2,449	20	2,429	1.91%	46	(5)	(0)	46	(3)
370	Meters	2,004	-	2,004	5.56%	111	(80)	(2)	109	21
371	Install. on Cust. Premises	11	-	11	5.56%	1	-	-	1	2
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	2,149	-	2,149	2.18%	47	(3)	(0)	47	0
1725 & 1735 GENERAL										
389	Land and Land Rights	303	-	303	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	10,899	2	10,897	3.77%	411	453	9	419	(261)
382	Computers	2,616	-	2,616	20.00%	523	(261)	(26)	497	273
391.2	Office Furniture & Equip.	119	-	119	6.00%	7	(24)	(1)	6	(10)
383	Software	171	-	171	10.00%	17	-	-	17	2
	Office Furniture & Equip. - G/L	-	-	-	0.00%	-	-	-	-	118
392	Transportation Equip.	3,056	177	2,879	11.31%	326	258	15	340	-
393	Stores Equip.	110	-	110	6.67%	7	-	-	7	3
394	Tools, Shop, & Garage Equip.	445	13	432	6.67%	29	(1)	(0)	29	(6)
395	Laboratory Equip.	167	-	167	4.00%	7	-	-	7	-
396	Power Operated Equip.	5,267	-	5,267	3.14%	165	(6)	(0)	165	(38)
397	Communication Equip.	6,951	-	6,951	4.47%	311	222	5	316	(12)
398	Misc. Equip.	402	-	402	6.67%	27	-	-	27	(7)
399	Other Tangible Property	351	-	351	5.00%	18	-	-	18	1
	Capital Inventory	-	-	-	0.00%	-	-	-	-	-
	Insurance Proceeds	(13,139)	-	(13,139)		(292)	-	-	(292)	-
	Subtotal Zone Specific	497,628	5,140	492,488		14,832	19,463	280	15,112	951
	Common Cost									
	Corporate								1,858	340
	Regional								602	(3)
	Distribution Related								111	-
	Subtotal Common Cost								2,570	337
	Total	497,628	5,140	492,488		14,832	19,463	280	17,682	1,288

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2016/17 Amortization Expense - Snare Zone ($000)

FERC	DESCRIPTION	2016/17 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	-	-	-	4.00%	-	-	-	-	-
121	Wind	-	-	-	2.75%	-	-	-	-	-
131	Heat Recovery Systems	-	-	-	3.57%	-	-	-	-	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	3,499	-	3,499	0.00%	-	-	-	-	-
331	Structures & Improvements	10,738	34	10,704	1.05%	112	247	1	114	(11)
332	Resv., Dams & Waterways	61,820	-	61,820	1.05%	649	486	3	652	43
333	Turbines and Generators	18,492	156	18,337	2.10%	385	11,775	124	509	88
334	Accessory Electric Equip.	15,070	24	15,046	2.63%	396	111	1	397	(45)
335	Misc. Power Plant Equip.	2,471	371	2,100	5.25%	110	125	3	114	(36)
336	Roads & Bridges	9,237	-	9,237	2.10%	194	-	-	194	78
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	6,576	-	6,576	1.05%	69	-	-	69	
332	Resv., Dams & Waterways	6,110	-	6,110	1.05%	64	-	-	64	
333	Turbines and Generators	9,891	-	9,891	2.10%	208	-	-	208	
334	Accessory Electric Equip.	2,591	-	2,591	2.63%	68	-	-	68	
335	Misc. Power Plant Equip.	735	-	735	5.25%	39	-	-	39	
336	Roads & Bridges	439	-	439	2.10%	9	-	-	9	
1722 & 1732 DIESEL										
340	Land and Land Rights	70	-	70	0.00%	-	-	-	-	-
341	Structures & Improvements	8,208	25	8,183	3.37%	276	645	11	287	53
342	Fuel Holders, Prod., & Access.	2,048	-	2,048	3.66%	75	9	0	75	7
343	Prime Movers	14,934	-	14,934	4.58%	684	5,850	134	818	66
344	Generators	1,616	-	1,616	3.75%	61	(14)	(0)	60	3
345	Accessory Electric Equip.	4,938	-	4,938	4.38%	216	201	4	221	-
346	Misc. Power Plant Equip.	830	-	830	4.55%	38	41	1	39	(13)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	5	-	5	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	2,907	-	2,907	1.54%	45	-	-	45	11
352	Structures & Improvements	3,644	-	3,644	2.50%	91	-	-	91	7
353	Station Equipment	14,318	171	14,147	3.62%	512	379	7	519	-
354	Towers & Fixtures	13,864	-	13,864	1.62%	225	(0)	(0)	225	129
355	Poles & Fixtures	1,365	-	1,365	2.33%	32	-	-	32	5
356	OH Conductors & Devices	8,948	-	8,948	1.75%	157	1,455	13	169	39
357	Underground Conduit	12	-	12	3.33%	0	-	-	0	(0)
358	Underground Conduct. & Dev.	16	-	16	3.33%	1	-	-	1	(0)
359	Roads & Trails	1,010	-	1,010	2.50%	25	-	-	25	(11)
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	11	-	11	0.00%	-	-	-	-	-
361	Structures & Improvements	19	-	19	2.50%	0	-	-	0	0
362	Station Equipment	300	-	300	4.00%	12	49	1	13	2
363	Storage Battery Equip.	39	-	39	6.67%	3	-	-	3	(19)
364	Poles & Fixtures	2,438	33	2,405	2.10%	50	(21)	(0)	50	(6)
365	OH Conductors & Devices	824	6	818	1.91%	16	(1)	(0)	16	(2)
366	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
367	Undergrd Conduct. & Devices	8	-	8	3.33%	0	-	-	0	0
368	Line Transformers	1,153	3	1,151	2.00%	23	(32)	(0)	23	(5)
369	Services	324	20	304	1.91%	6	(6)	(0)	6	(0)
370	Meters	97	-	97	5.56%	5	33	1	6	2
371	Install. on Cust. Premises	-	-	-	5.56%	-	-	-	-	-
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	332	-	332	2.18%	7	(0)	(0)	7	0
1725 & 1735 GENERAL										
389	Land and Land Rights	7	-	7	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	2,660	2	2,658	3.77%	100	(148)	(3)	97	(66)
391.1	Computers	2,241	-	2,241	20.00%	448	(406)	(41)	408	167
391.2	Office Furniture & Equip.	67	-	67	6.00%	4	(39)	(1)	3	(4)
391.3	Software	62	-	62	10.00%	6	8	0	7	1
		-	-	-	0.00%	-	-	-	-	72
392	Transportation Equip.	1,076	143	933	11.31%	105	(34)	(2)	104	-
393	Stores Equip.	27	-	27	6.67%	2	-	-	2	1
394	Tools, Shop, & Garage Equip.	174	-	174	6.67%	12	(2)	(0)	12	(2)
395	Laboratory Equip.	114	-	114	4.00%	5	-	-	5	-
396	Power Operated Equip.	2,866	-	2,866	3.14%	90	(8)	(0)	90	(22)
397	Communication Equip.	3,345	-	3,345	4.47%	150	360	8	158	(7)
398	Misc. Equip.	125	-	125	6.67%	8	-	-	8	(2)
399	Other Tangible Property	75	-	75	5.00%	4	-	-	4	0
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(1,605)	-			(28)			(28)	
	Subtotal Zone Specific	243,185	988	243,802		5,769	21,062	265	6,034	526
	Common Cost									
	Corporate								880	198
	Regional								187	(0)
	Distribution Related								3	
	Subtotal Common Cost								1,070	198
	Total	243,185	988	243,802		5,769	21,062	265	7,103	723

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2016/17 Amortization Expense - Taltson Zone ($000)

FERC	DESCRIPTION	2016/17 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	-	-	-	4.00%	-	-	-	-	-
121	Wind	-	-	-	2.75%	-	-	-	-	-
131	Heat Recovery Systems	-	-	-	3.57%	-	-	-	-	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	610	-	610	0.00%	-	-	-	-	-
331	Structures & Improvements	5,311	37	5,274	1.05%	55	(0)	(0)	55	(5)
332	Resv., Dams & Waterways	3,263	-	3,263	1.05%	34	(0)	(0)	34	2
333	Turbines and Generators	3,972	1,428	2,544	2.10%	53	-	-	53	18
334	Accessory Electric Equip.	3,636	-	3,636	2.63%	96	(0)	(0)	96	(11)
335	Misc. Power Plant Equip.	336	-	336	5.25%	18	65	2	19	(4)
336	Roads & Bridges	1,559	-	1,559	2.10%	33	-	-	33	13
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	
334	Accessory Electric Equip.	-	-	-	2.63%	-	-	-	-	
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	
1722 & 1732 DIESEL										
340	Land and Land Rights	70	-	70	0.00%	-	-	-	-	-
341	Structures & Improvements	1,750	-	1,750	3.37%	59	(6)	(0)	59	11
342	Fuel Holders, Prod., & Access.	352	-	352	3.66%	13	(7)	(0)	13	1
343	Prime Movers	2,292	84	2,208	4.58%	101	(61)	(1)	100	10
344	Generators	795	-	795	3.75%	30	(1)	(0)	30	2
345	Accessory Electric Equip.	2,033	-	2,033	4.38%	89	700	15	104	-
346	Misc. Power Plant Equip.	35	-	35	4.55%	2	-	-	2	(1)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	215	-	215	1.54%	3	-	-	3	1
352	Structures & Improvements	157	-	157	2.50%	4	-	-	4	0
353	Station Equipment	3,059	29	3,030	3.62%	110	59	1	111	-
354	Towers & Fixtures	1,537	9	1,527	1.62%	25	(0)	(0)	25	13
355	Poles & Fixtures	404	-	404	2.33%	9	-	-	9	2
356	OH Conductors & Devices	1,850	9	1,840	1.75%	32	73	1	33	8
357	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
358	Underground Conduct. & Dev.	-	-	-	3.33%	-	-	-	-	-
359	Roads & Trails	-	-	-	2.50%	-	-	-	-	-
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
361	Structures & Improvements	1	-	1	2.50%	0	-	-	0	0
362	Station Equipment	1,112	-	1,112	4.00%	44	-	-	44	6
363	Storage Battery Equip.	-	-	-	6.67%	-	-	-	-	-
364	Poles & Fixtures	2,526	4	2,522	2.10%	53	(2)	(0)	53	(6)
365	OH Conductors & Devices	835	-	835	1.91%	16	598	6	22	(2)
366	Underground Conduit	72	-	72	3.33%	2	-	-	2	0
367	Undergrd Conduct. & Devices	432	-	432	3.33%	14	-	-	14	5
368	Line Transformers	1,255	6	1,249	2.00%	25	(3)	(0)	25	(5)
369	Services	139	-	139	1.91%	3	(1)	(0)	3	(0)
370	Meters	322	-	322	5.56%	18	632	18	35	4
371	Install. on Cust. Premises	-	-	-	5.56%	-	-	-	-	-
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	146	-	146	2.18%	3	(1)	(0)	3	0
1725 & 1735 GENERAL										
389	Land and Land Rights	75	-	75	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	1,207	-	1,207	3.77%	45	(11)	(0)	45	(30)
391.1	Computers	241	-	241	20.00%	48	(0)	(0)	48	24
391.2	Office Furniture & Equip.	4	-	4	6.00%	0	(3)	(0)	0	(0)
391.3	Software	30	-	30	10.00%	3	-	-	3	0
		-	-	-	0.00%	-	-	-	-	10
392	Transportation Equip.	385	-	385	11.31%	44	(7)	(0)	43	-
393	Stores Equip.	-	-	-	6.67%	-	-	-	-	-
394	Tools, Shop, & Garage Equip.	33	-	33	6.67%	2	(0)	(0)	2	(0)
395	Laboratory Equip.	15	-	15	4.00%	1	-	-	1	-
396	Power Operated Equip.	1,150	-	1,150	3.14%	36	(1)	(0)	36	(9)
397	Communication Equip.	764	-	764	4.47%	34	70	2	36	(2)
398	Misc. Equip.	66	-	66	6.67%	4	-	-	4	(1)
399	Other Tangible Property	17	-	17	5.00%	1	-	-	1	0
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(416)	-			(15)			(15)	
	Subtotal Zone Specific	43,646	1,606	42,456		1,148	2,094	41	1,189	57
	Common Cost									
	Corporate								282	63
	Regional								60	(0)
	Distribution Related								4	
	Subtotal Common Cost								347	63
	Total	43,646	1,606	42,456		1,148	2,094	41	1,536	120

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2016/17 Amortization Expense - Thermal Zone ($000)

FERC	DESCRIPTION	2016/17 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	3,655	-	3,655	4.00%	146	1,721	34	181	5
121	Wind	353	363	(10)	2.75%	(0)	-	-	(0)	(19)
131	Heat Recovery Systems	5,656	-	5,656	3.57%	202	(0)	(0)	202	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	-
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	-
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	-
334	Accessory Electric Equip.	-	-	-	2.63%	-	-	-	-	-
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	-
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	-
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	
334	Accessory Electric Equip.	-	-	-	2.63%	-	-	-	-	
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	
1722 & 1732 DIESEL										
340	Land and Land Rights	964	32	932	0.00%	-	-	-	-	-
341	Structures & Improvements	39,083	166	38,917	3.37%	1,311	659	11	1,323	222
342	Fuel Holders, Prod., & Access.	22,159	-	22,159	3.66%	811	1,127	21	832	72
343	Prime Movers	45,766	1,894	43,872	4.58%	2,009	540	12	2,022	194
344	Generators	5,829	5	5,824	3.75%	218	(3)	(0)	218	11
345	Accessory Electric Equip.	18,839	30	18,809	4.38%	824	150	3	827	-
346	Misc. Power Plant Equip.	1,097	-	1,097	4.55%	50	-	-	50	(18)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	-	-	-	1.54%	-	-	-	-	-
352	Structures & Improvements	-	-	-	2.50%	-	-	-	-	-
353	Station Equipment	-	-	-	3.62%	-	-	-	-	-
354	Towers & Fixtures	-	-	-	1.62%	-	-	-	-	-
355	Poles & Fixtures	-	-	-	2.33%	-	-	-	-	-
356	OH Conductors & Devices	-	-	-	1.75%	-	-	-	-	-
357	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
358	Underground Conduct. & Dev.	-	-	-	3.33%	-	-	-	-	-
359	Roads & Trails	-	-	-	2.50%	-	-	-	-	-
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	328	-	328	0.00%	-	-	-	-	-
361	Structures & Improvements	810	-	810	2.50%	20	-	-	20	5
362	Station Equipment	696	-	696	4.00%	28	-	-	28	5
363	Storage Battery Equip.	23	-	23	6.67%	2	-	-	2	(11)
364	Poles & Fixtures	10,250	-	10,250	2.10%	215	(4)	(0)	215	(23)
365	OH Conductors & Devices	2,756	-	2,756	1.91%	53	305	3	56	(6)
366	Underground Conduit	57	-	57	3.33%	2	-	-	2	0
367	Undergrd Conduct. & Devices	244	-	244	3.33%	8	-	-	8	3
368	Line Transformers	4,098	8	4,090	2.00%	82	(7)	(0)	82	(16)
369	Services	1,996	-	1,996	1.91%	38	(1)	(0)	38	(2)
370	Meters	1,057	-	1,057	5.56%	59	(46)	(1)	57	15
371	Install. on Cust. Premises	11	-	11	5.56%	1	-	-	1	2
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	1,677	-	1,677	2.18%	37	(2)	(0)	37	0
1725 & 1735 GENERAL										
389	Land and Land Rights	221	-	221	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	6,857	-	6,857	3.77%	259	(2)	(0)	258	(166)
391.1	Computers	750	-	750	20.00%	150	(17)	(2)	148	82
391.2	Office Furniture & Equip.	111	-	111	6.00%	7	(2)	(0)	7	(6)
391.3	Software	70	-	70	10.00%	7	-	-	7	1
		-	-	-	0.00%	-	-	-	-	35
392	Transportation Equip.	1,720	34	1,686	11.31%	191	(21)	(1)	190	-
393	Stores Equip.	84	-	84	6.67%	6	-	-	6	2
394	Tools, Shop, & Garage Equip.	242	13	229	6.67%	15	(0)	(0)	15	(3)
395	Laboratory Equip.	39	-	39	4.00%	2	-	-	2	-
396	Power Operated Equip.	1,264	-	1,264	3.14%	40	(1)	(0)	40	(7)
397	Communication Equip.	2,004	-	2,004	4.47%	90	(2)	(0)	90	(4)
398	Misc. Equip.	211	-	211	6.67%	14	-	-	14	(4)
399	Other Tangible Property	258	-	258	5.00%	13	-	-	13	1
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(11,118)	-			(249)			(249)	
	Subtotal Zone Specific	170,116	2,546	178,688		6,658	4,394	80	6,738	368
	Common Cost									
	Corporate								351	79
	Regional								56	(3)
	Distribution Related								12	
	Subtotal Common Cost								419	76
	Total	170,116	2,546	178,688		6,658	4,394	80	7,158	444

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2017/18 Amortization Expense - Snare Zone ($000)

FERC	DESCRIPTION	2017/18 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	-	-	-	4.00%	-	-	-	-	-
121	Wind	-	-	-	2.75%	-	-	-	-	-
131	Heat Recovery Systems	-	-	-	3.57%	-	-	-	-	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	3,499	-	3,499	0.00%	-	-	-	-	-
331	Structures & Improvements	10,985	34	10,951	1.05%	115	(1)	(0)	115	(11)
332	Resv., Dams & Waterways	62,307	-	62,307	1.05%	654	(11)	(0)	654	43
333	Turbines and Generators	30,267	156	30,111	2.10%	632	70	1	633	88
334	Accessory Electric Equip.	15,181	24	15,158	2.63%	399	27	0	399	(45)
335	Misc. Power Plant Equip.	2,596	371	2,225	5.25%	117	1,032	27	144	(36)
336	Roads & Bridges	9,237	-	9,237	2.10%	194	40	0	194	78
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	6,576	-	6,576	1.05%	69	-	-	69	
332	Resv., Dams & Waterways	6,110	-	6,110	1.05%	64	-	-	64	
333	Turbines and Generators	9,891	-	9,891	2.10%	208	-	-	208	
334	Accessory Electric Equip.	2,591	-	2,591	2.63%	68	-	-	68	
335	Misc. Power Plant Equip.	735	-	735	5.25%	39	-	-	39	
336	Roads & Bridges	439	-	439	2.10%	9	-	-	9	
1722 & 1732 DIESEL										
340	Land and Land Rights	70	-	70	0.00%	-	-	-	-	-
341	Structures & Improvements	8,853	25	8,828	3.37%	298	(15)	(0)	297	53
342	Fuel Holders, Prod., & Access.	2,057	-	2,057	3.66%	75	(18)	(0)	75	7
343	Prime Movers	20,784	-	20,784	4.58%	952	(162)	(4)	948	66
344	Generators	1,602	-	1,602	3.75%	60	(3)	(0)	60	3
345	Accessory Electric Equip.	5,140	-	5,140	4.38%	225	2,713	59	285	-
346	Misc. Power Plant Equip.	871	-	871	4.55%	40	75	2	41	(13)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	5	-	5	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	2,907	-	2,907	1.54%	45	-	-	45	11
352	Structures & Improvements	3,644	-	3,644	2.50%	91	-	-	91	7
353	Station Equipment	14,697	171	14,526	3.62%	526	790	14	540	-
354	Towers & Fixtures	13,863	-	13,863	1.62%	225	(0)	(0)	225	129
355	Poles & Fixtures	1,365	-	1,365	2.33%	32	150	2	34	5
356	OH Conductors & Devices	10,403	-	10,403	1.75%	182	150	1	183	39
357	Underground Conduit	12	-	12	3.33%	0	-	-	0	(0)
358	Underground Conduct. & Dev.	16	-	16	3.33%	1	-	-	1	(0)
359	Roads & Trails	1,010	-	1,010	2.50%	25	-	-	25	(11)
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	11	-	11	0.00%	-	-	-	-	-
361	Structures & Improvements	19	-	19	2.50%	0	-	-	0	0
362	Station Equipment	349	-	349	4.00%	14	-	-	14	2
363	Storage Battery Equip.	39	-	39	6.67%	3	-	-	3	(19)
364	Poles & Fixtures	2,417	33	2,384	2.10%	50	(5)	(0)	50	(6)
365	OH Conductors & Devices	823	6	817	1.91%	16	(0)	(0)	16	(2)
366	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
367	Undergrd Conduct. & Devices	8	-	8	3.33%	0	-	-	0	0
368	Line Transformers	1,121	3	1,118	2.00%	22	(8)	(0)	22	(5)
369	Services	318	20	298	1.91%	6	(1)	(0)	6	(0)
370	Meters	130	-	130	5.56%	7	-	-	7	2
371	Install. on Cust. Premises	-	-	-	5.56%	-	-	-	-	-
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	332	-	332	2.18%	7	-	-	7	0
1725 & 1735 GENERAL										
389	Land and Land Rights	7	-	7	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	2,512	2	2,510	3.77%	95	(35)	(1)	94	(66)
391.1	Computers	1,836	-	1,836	20.00%	367	(100)	(10)	357	167
391.2	Office Furniture & Equip.	28	-	28	6.00%	2	(9)	(0)	1	(4)
391.3	Software	70	-	70	10.00%	7	-	-	7	1
		-	-	-	0.00%	-	-	-	-	72
392	Transportation Equip.	1,042	143	899	11.31%	102	(25)	(1)	100	-
393	Stores Equip.	27	-	27	6.67%	2	-	-	2	1
394	Tools, Shop, & Garage Equip.	172	-	172	6.67%	11	(1)	(0)	11	(2)
395	Laboratory Equip.	114	-	114	4.00%	5	-	-	5	-
396	Power Operated Equip.	2,858	-	2,858	3.14%	90	(2)	(0)	90	(22)
397	Communication Equip.	3,705	-	3,705	4.47%	166	223	5	171	(7)
398	Misc. Equip.	125	-	125	6.67%	8	-	-	8	(2)
399	Other Tangible Property	75	-	75	5.00%	4	-	-	4	0
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(1,605)	-			(28)			(28)	
	Subtotal Zone Specific	264,247	988	264,864		6,298	4,872	95	6,394	526
	Common Cost									
	Corporate								994	198
	Regional								262	(0)
	Distribution Related								7	
	Subtotal Common Cost								1,263	198
	Total	264,247	988	264,864		6,298	4,872	95	7,656	723

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2017/18 Amortization Expense - Taltson Zone ($000)

FERC	DESCRIPTION	2017/18 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	-	-	-	4.00%	-	-	-	-	-
121	Wind	-	-	-	2.75%	-	-	-	-	-
131	Heat Recovery Systems	-	-	-	3.57%	-	-	-	-	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	610	-	610	0.00%	-	-	-	-	-
331	Structures & Improvements	5,311	37	5,273	1.05%	55	(0)	(0)	55	(5)
332	Resv., Dams & Waterways	3,263	-	3,263	1.05%	34	(0)	(0)	34	2
333	Turbines and Generators	3,972	1,428	2,544	2.10%	53	-	-	53	18
334	Accessory Electric Equip.	3,635	-	3,635	2.63%	96	(0)	(0)	96	(11)
335	Misc. Power Plant Equip.	401	-	401	5.25%	21	100	3	24	(4)
336	Roads & Bridges	1,559	-	1,559	2.10%	33	-	-	33	13
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	
334	Accessory Electric Equip.	-	-	-	2.63%	-	-	-	-	
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	
1722 & 1732 DIESEL										
340	Land and Land Rights	70	-	70	0.00%	-	-	-	-	-
341	Structures & Improvements	1,744	-	1,744	3.37%	59	(1)	(0)	59	11
342	Fuel Holders, Prod., & Access.	346	-	346	3.66%	13	(1)	(0)	13	1
343	Prime Movers	2,231	84	2,147	4.58%	98	(10)	(0)	98	10
344	Generators	793	-	793	3.75%	30	(0)	(0)	30	2
345	Accessory Electric Equip.	2,733	-	2,733	4.38%	120	(3)	(0)	120	-
346	Misc. Power Plant Equip.	35	-	35	4.55%	2	-	-	2	(1)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	215	-	215	1.54%	3	-	-	3	1
352	Structures & Improvements	157	-	157	2.50%	4	-	-	4	0
353	Station Equipment	3,118	29	3,089	3.62%	112	(0)	(0)	112	-
354	Towers & Fixtures	1,537	9	1,527	1.62%	25	(0)	(0)	25	13
355	Poles & Fixtures	404	-	404	2.33%	9	-	-	9	2
356	OH Conductors & Devices	1,923	9	1,913	1.75%	33	-	-	33	8
357	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
358	Underground Conduct. & Dev.	-	-	-	3.33%	-	-	-	-	-
359	Roads & Trails	-	-	-	2.50%	-	-	-	-	-
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
361	Structures & Improvements	1	-	1	2.50%	0	-	-	0	0
362	Station Equipment	1,112	-	1,112	4.00%	44	150	3	47	6
363	Storage Battery Equip.	-	-	-	6.67%	-	-	-	-	-
364	Poles & Fixtures	2,524	4	2,521	2.10%	53	(0)	(0)	53	(6)
365	OH Conductors & Devices	1,433	-	1,433	1.91%	27	(0)	(0)	27	(2)
366	Underground Conduit	72	-	72	3.33%	2	-	-	2	0
367	Undergrd Conduct. & Devices	432	-	432	3.33%	14	-	-	14	5
368	Line Transformers	1,252	6	1,246	2.00%	25	(0)	(0)	25	(5)
369	Services	139	-	139	1.91%	3	(0)	(0)	3	(0)
370	Meters	954	-	954	5.56%	53	(3)	(0)	53	4
371	Install. on Cust. Premises	-	-	-	5.56%	-	-	-	-	-
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	145	-	145	2.18%	3	(0)	(0)	3	0
1725 & 1735 GENERAL										
389	Land and Land Rights	75	-	75	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	1,196	-	1,196	3.77%	45	(2)	(0)	45	(30)
391.1	Computers	240	-	240	20.00%	48	(3)	(0)	48	24
391.2	Office Furniture & Equip.	1	-	1	6.00%	0	(0)	(0)	0	(0)
391.3	Software	30	-	30	10.00%	3	-	-	3	0
		-	-	-	0.00%	-	-	-	-	10
392	Transportation Equip.	377	-	377	11.31%	43	(1)	(0)	43	-
393	Stores Equip.	-	-	-	6.67%	-	-	-	-	-
394	Tools, Shop, & Garage Equip.	33	-	33	6.67%	2	(0)	(0)	2	(0)
395	Laboratory Equip.	15	-	15	4.00%	1	-	-	1	-
396	Power Operated Equip.	1,149	-	1,149	3.14%	36	(0)	(0)	36	(9)
397	Communication Equip.	834	-	834	4.47%	37	190	4	42	(2)
398	Misc. Equip.	66	-	66	6.67%	4	-	-	4	(1)
399	Other Tangible Property	17	-	17	5.00%	1	-	-	1	0
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(416)	-			(15)			(15)	
	Subtotal Zone Specific	45,740	1,606	44,550		1,231	413	9	1,240	57
	Common Cost									
	Corporate								319	63
	Regional								84	(0)
	Distribution Related								12	
	Subtotal Common Cost								415	63
	Total	45,740	1,606	44,550		1,231	413	9	1,655	120

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2017/18 Amortization Expense - Thermal Zone ($000)

FERC	DESCRIPTION	2017/18 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	5,376	-	5,376	4.00%	215	-	-	215	5
121	Wind	353	363	(10)	2.75%	(0)	-	-	(0)	(19)
131	Heat Recovery Systems	5,656	-	5,656	3.57%	202	(0)	(0)	202	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	-
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	-
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	-
334	Accessory Electric Equip.	-	-	-	2.63%	-	65	1	1	-
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	-
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	-
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	
334	Accessory Electric Equip.	-	-	-	2.63%	-	-	-	-	
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	
1722 & 1732 DIESEL										
340	Land and Land Rights	964	32	932	0.00%	-	-	-	-	-
341	Structures & Improvements	39,743	166	39,576	3.37%	1,334	3,308	56	1,389	222
342	Fuel Holders, Prod., & Access.	23,287	-	23,287	3.66%	852	1,367	25	877	72
343	Prime Movers	46,305	1,894	44,411	4.58%	2,034	1,198	27	2,061	194
344	Generators	5,826	5	5,821	3.75%	218	(5)	(0)	218	11
345	Accessory Electric Equip.	18,989	30	18,959	4.38%	830	900	20	850	-
346	Misc. Power Plant Equip.	1,097	-	1,097	4.55%	50	-	-	50	(18)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	-	-	-	1.54%	-	-	-	-	-
352	Structures & Improvements	-	-	-	2.50%	-	-	-	-	-
353	Station Equipment	-	-	-	3.62%	-	-	-	-	-
354	Towers & Fixtures	-	-	-	1.62%	-	-	-	-	-
355	Poles & Fixtures	-	-	-	2.33%	-	-	-	-	-
356	OH Conductors & Devices	-	-	-	1.75%	-	-	-	-	-
357	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
358	Underground Conduct. & Dev.	-	-	-	3.33%	-	-	-	-	-
359	Roads & Trails	-	-	-	2.50%	-	-	-	-	-
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	328	-	328	0.00%	-	-	-	-	-
361	Structures & Improvements	810	-	810	2.50%	20	-	-	20	5
362	Station Equipment	696	-	696	4.00%	28	381	8	35	5
363	Storage Battery Equip.	23	-	23	6.67%	2	161	5	7	(11)
364	Poles & Fixtures	10,245	-	10,245	2.10%	215	(8)	(0)	215	(23)
365	OH Conductors & Devices	3,060	-	3,060	1.91%	58	350	3	62	(6)
366	Underground Conduit	57	-	57	3.33%	2	-	-	2	0
367	Undergrd Conduct. & Devices	244	-	244	3.33%	8	-	-	8	3
368	Line Transformers	4,092	8	4,084	2.00%	82	(12)	(0)	82	(16)
369	Services	1,995	-	1,995	1.91%	38	(2)	(0)	38	(2)
370	Meters	1,010	-	1,010	5.56%	56	(87)	(2)	54	15
371	Install. on Cust. Premises	11	-	11	5.56%	1	-	-	1	2
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	1,675	-	1,675	2.18%	37	(3)	(0)	36	0
1725 & 1735 GENERAL										
389	Land and Land Rights	221	-	221	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	6,855	-	6,855	3.77%	258	373	7	265	(166)
391.1	Computers	732	-	732	20.00%	146	(89)	(9)	138	82
391.2	Office Furniture & Equip.	109	-	109	6.00%	7	(9)	(0)	6	(6)
391.3	Software	70	-	70	10.00%	7	-	-	7	1
		-	-	-	0.00%	-	-	-	-	35
392	Transportation Equip.	1,699	34	1,666	11.31%	188	(37)	(2)	186	-
393	Stores Equip.	84	-	84	6.67%	6	-	-	6	2
394	Tools, Shop, & Garage Equip.	242	13	228	6.67%	15	(1)	(0)	15	(3)
395	Laboratory Equip.	39	-	39	4.00%	2	-	-	2	-
396	Power Operated Equip.	1,263	-	1,263	3.14%	40	(2)	(0)	40	(7)
397	Communication Equip.	2,002	-	2,002	4.47%	90	(3)	(0)	89	(4)
398	Misc. Equip.	211	-	211	6.67%	14	-	-	14	(4)
399	Other Tangible Property	258	-	258	5.00%	13	-	-	13	1
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(11,118)	-			(249)			(249)	
	Subtotal Zone Specific	174,510	2,546	183,083		6,818	7,846	138	6,956	368
	Common Cost									
	Corporate								398	79
	Regional								125	(3)
	Distribution Related								33	
	Subtotal Common Cost								556	76
	Total	174,510	2,546	183,083		6,818	7,846	138	7,512	445

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2018/19 Amortization Expense - Snare Zone ($000)

FERC	DESCRIPTION	2018/19 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	-	-	-	4.00%	-	-	-	-	-
121	Wind	-	-	-	2.75%	-	-	-	-	-
131	Heat Recovery Systems	-	-	-	3.57%	-	-	-	-	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	3,499	-	3,499	0.00%	-	-	-	-	-
331	Structures & Improvements	10,984	34	10,949	1.05%	115	117	1	116	(11)
332	Resv., Dams & Waterways	62,296	-	62,296	1.05%	654	(25)	(0)	654	43
333	Turbines and Generators	30,337	156	30,181	2.10%	634	7,862	83	716	88
334	Accessory Electric Equip.	15,208	24	15,184	2.63%	399	(8)	(0)	399	(45)
335	Misc. Power Plant Equip.	3,628	371	3,258	5.25%	171	453	12	183	(36)
336	Roads & Bridges	9,277	-	9,277	2.10%	195	-	-	195	78
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	6,576	-	6,576	1.05%	69	-	-	69	
332	Resv., Dams & Waterways	6,110	-	6,110	1.05%	64	-	-	64	
333	Turbines and Generators	9,891	-	9,891	2.10%	208	-	-	208	
334	Accessory Electric Equip.	2,591	-	2,591	2.63%	68	-	-	68	
335	Misc. Power Plant Equip.	735	-	735	5.25%	39	-	-	39	
336	Roads & Bridges	439	-	439	2.10%	9	-	-	9	
1722 & 1732 DIESEL										
340	Land and Land Rights	70	-	70	0.00%	-	-	-	-	-
341	Structures & Improvements	8,838	25	8,813	3.37%	297	(36)	(1)	296	53
342	Fuel Holders, Prod., & Access.	2,039	-	2,039	3.66%	75	(42)	(1)	74	7
343	Prime Movers	20,622	-	20,622	4.58%	944	415	10	954	66
344	Generators	1,598	-	1,598	3.75%	60	(8)	(0)	60	3
345	Accessory Electric Equip.	7,852	-	7,852	4.38%	344	606	13	357	-
346	Misc. Power Plant Equip.	946	-	946	4.55%	43	75	2	45	(13)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	5	-	5	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	2,907	-	2,907	1.54%	45	-	-	45	11
352	Structures & Improvements	3,644	-	3,644	2.50%	91	1,229	15	106	7
353	Station Equipment	15,487	171	15,316	3.62%	554	967	18	572	-
354	Towers & Fixtures	13,863	-	13,863	1.62%	225	(0)	(0)	225	129
355	Poles & Fixtures	1,515	-	1,515	2.33%	35	150	2	37	5
356	OH Conductors & Devices	10,553	-	10,553	1.75%	185	-	-	185	39
357	Underground Conduit	12	-	12	3.33%	0	-	-	0	(0)
358	Underground Conduct. & Dev.	16	-	16	3.33%	1	-	-	1	(0)
359	Roads & Trails	1,010	-	1,010	2.50%	25	-	-	25	(11)
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	11	-	11	0.00%	-	-	-	-	-
361	Structures & Improvements	19	-	19	2.50%	0	-	-	0	0
362	Station Equipment	349	-	349	4.00%	14	100	2	16	2
363	Storage Battery Equip.	39	-	39	6.67%	3	-	-	3	(19)
364	Poles & Fixtures	2,412	33	2,379	2.10%	50	(11)	(0)	50	(6)
365	OH Conductors & Devices	823	6	817	1.91%	16	(0)	(0)	16	(2)
366	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
367	Undergrd Conduct. & Devices	8	-	8	3.33%	0	-	-	0	0
368	Line Transformers	1,113	3	1,111	2.00%	22	(18)	(0)	22	(5)
369	Services	317	20	297	1.91%	6	(3)	(0)	6	(0)
370	Meters	130	-	130	5.56%	7	(1)	(0)	7	2
371	Install. on Cust. Premises	-	-	-	5.56%	-	-	-	-	-
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	332	-	332	2.18%	7	(0)	(0)	7	0
1725 & 1735 GENERAL										
389	Land and Land Rights	7	-	7	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	2,477	2	2,475	3.77%	93	(82)	(2)	92	(66)
391.1	Computers	1,735	-	1,735	20.00%	347	(231)	(23)	324	167
391.2	Office Furniture & Equip.	19	-	19	6.00%	1	(22)	(1)	0	(4)
391.3	Software	70	-	70	10.00%	7	-	-	7	1
		-	-	-	0.00%	-	-	-	-	72
392	Transportation Equip.	1,018	143	874	11.31%	99	(57)	(3)	96	-
393	Stores Equip.	27	-	27	6.67%	2	-	-	2	1
394	Tools, Shop, & Garage Equip.	171	-	171	6.67%	11	(1)	(0)	11	(2)
395	Laboratory Equip.	114	-	114	4.00%	5	-	-	5	-
396	Power Operated Equip.	2,857	-	2,857	3.14%	90	(4)	(0)	90	(22)
397	Communication Equip.	3,928	-	3,928	4.47%	176	225	5	181	(7)
398	Misc. Equip.	125	-	125	6.67%	8	-	-	8	(2)
399	Other Tangible Property	75	-	75	5.00%	4	-	-	4	0
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(1,605)	-			(28)			(28)	
	Subtotal Zone Specific	269,119	988	269,736		6,489	11,650	130	6,619	526
	Common Cost									
	Corporate								1,079	198
	Regional								310	(0)
	Distribution Related								15	
	Subtotal Common Cost								1,404	198
	Total	269,119	988	269,736		6,489	11,650	130	8,023	723

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2018/19 Amortization Expense - Taltson Zone ($000)

FERC	DESCRIPTION	2018/19 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	-	-	-	4.00%	-	-	-	-	-
121	Wind	-	-	-	2.75%	-	-	-	-	-
131	Heat Recovery Systems	-	-	-	3.57%	-	-	-	-	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	610	-	610	0.00%	-	-	-	-	-
331	Structures & Improvements	5,311	37	5,273	1.05%	55	-	-	55	(5)
332	Resv., Dams & Waterways	3,262	-	3,262	1.05%	34	-	-	34	2
333	Turbines and Generators	3,972	1,428	2,544	2.10%	53	-	-	53	18
334	Accessory Electric Equip.	3,635	-	3,635	2.63%	96	-	-	96	(11)
335	Misc. Power Plant Equip.	501	-	501	5.25%	26	-	-	26	(4)
336	Roads & Bridges	1,559	-	1,559	2.10%	33	-	-	33	13
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	
334	Accessory Electric Equip.	-	-	-	2.63%	-	-	-	-	
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	
1722 & 1732 DIESEL										
340	Land and Land Rights	70	-	70	0.00%	-	-	-	-	-
341	Structures & Improvements	1,743	-	1,743	3.37%	59	(1)	(0)	59	11
342	Fuel Holders, Prod., & Access.	344	-	344	3.66%	13	(1)	(0)	13	1
343	Prime Movers	2,221	84	2,137	4.58%	98	(10)	(0)	98	10
344	Generators	793	-	793	3.75%	30	(0)	(0)	30	2
345	Accessory Electric Equip.	2,730	-	2,730	4.38%	120	(3)	(0)	119	-
346	Misc. Power Plant Equip.	35	-	35	4.55%	2	-	-	2	(1)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	215	-	215	1.54%	3	-	-	3	1
352	Structures & Improvements	157	-	157	2.50%	4	-	-	4	0
353	Station Equipment	3,118	29	3,089	3.62%	112	-	-	112	-
354	Towers & Fixtures	1,537	9	1,527	1.62%	25	-	-	25	13
355	Poles & Fixtures	404	-	404	2.33%	9	-	-	9	2
356	OH Conductors & Devices	1,923	9	1,913	1.75%	33	-	-	33	8
357	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
358	Underground Conduct. & Dev.	-	-	-	3.33%	-	-	-	-	-
359	Roads & Trails	-	-	-	2.50%	-	-	-	-	-
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
361	Structures & Improvements	1	-	1	2.50%	0	-	-	0	0
362	Station Equipment	1,262	-	1,262	4.00%	50	325	7	57	6
363	Storage Battery Equip.	-	-	-	6.67%	-	-	-	-	-
364	Poles & Fixtures	2,524	4	2,520	2.10%	53	(0)	(0)	53	(6)
365	OH Conductors & Devices	1,433	-	1,433	1.91%	27	(0)	(0)	27	(2)
366	Underground Conduit	72	-	72	3.33%	2	-	-	2	0
367	Undergrd Conduct. & Devices	432	-	432	3.33%	14	-	-	14	5
368	Line Transformers	1,252	6	1,246	2.00%	25	(0)	(0)	25	(5)
369	Services	139	-	139	1.91%	3	(0)	(0)	3	(0)
370	Meters	950	-	950	5.56%	53	(3)	(0)	53	4
371	Install. on Cust. Premises	-	-	-	5.56%	-	-	-	-	-
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	145	-	145	2.18%	3	(0)	(0)	3	0
1725 & 1735 GENERAL										
389	Land and Land Rights	75	-	75	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	1,195	-	1,195	3.77%	45	(2)	(0)	45	(30)
391.1	Computers	237	-	237	20.00%	47	(6)	(1)	47	24
391.2	Office Furniture & Equip.	1	-	1	6.00%	0	(1)	(0)	0	(0)
391.3	Software	30	-	30	10.00%	3	-	-	3	0
		-	-	-	0.00%	-	-	-	-	10
392	Transportation Equip.	376	-	376	11.31%	43	(1)	(0)	42	-
393	Stores Equip.	-	-	-	6.67%	-	-	-	-	-
394	Tools, Shop, & Garage Equip.	33	-	33	6.67%	2	(0)	(0)	2	(0)
395	Laboratory Equip.	15	-	15	4.00%	1	-	-	1	-
396	Power Operated Equip.	1,149	-	1,149	3.14%	36	(0)	(0)	36	(9)
397	Communication Equip.	1,024	-	1,024	4.47%	46	(0)	(0)	46	(2)
398	Misc. Equip.	66	-	66	6.67%	4	-	-	4	(1)
399	Other Tangible Property	17	-	17	5.00%	1	-	-	1	0
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(416)	-			(15)			(15)	
	Subtotal Zone Specific	46,153	1,606	44,963		1,249	296	5	1,254	57
	Common Cost									
	Corporate								347	63
	Regional								100	(0)
	Distribution Related								25	
	Subtotal Common Cost								472	63
	Total	46,153	1,606	44,963		1,249	296	5	1,726	120

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Calculation of 2018/19 Amortization Expense - Thermal Zone ($000)

FERC	DESCRIPTION	2018/19 Opening PPE	Inactive Assets	2013/14 Opening Amortization PPE	Amortization Rate	Amortization on Opening Balance	Net Capital Additions	Amortization on Capital Additions	Total 2017 Depreciation	True-up Provision
1729 EUG										
118	High water temp equip	5,376	-	5,376	4.00%	215	-	-	215	5
121	Wind	353	363	(10)	2.75%	(0)	-	-	(0)	(19)
131	Heat Recovery Systems	5,656	-	5,656	3.57%	202	(0)	(0)	202	-
155	Microturbines	-	-	-	4.00%	-	-	-	-	-
1721 & 1731 HYDRO										
330	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	-
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	-
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	-
334	Accessory Electric Equip.	65	-	65	2.63%	2	-	-	2	-
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	-
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	-
1726 LEASED ASSETS										
330	Land and Land Rights	-	-		0.00%	-	-	-	-	
331	Structures & Improvements	-	-	-	1.05%	-	-	-	-	
332	Resv., Dams & Waterways	-	-	-	1.05%	-	-	-	-	
333	Turbines and Generators	-	-	-	2.10%	-	-	-	-	
334	Accessory Electric Equip.	-	-	-	2.63%	-	-	-	-	
335	Misc. Power Plant Equip.	-	-	-	5.25%	-	-	-	-	
336	Roads & Bridges	-	-	-	2.10%	-	-	-	-	
1722 & 1732 DIESEL										
340	Land and Land Rights	964	32	932	0.00%	-	-	-	-	-
341	Structures & Improvements	43,051	166	42,884	3.37%	1,445	4,952	83	1,529	222
342	Fuel Holders, Prod., & Access.	24,653	-	24,653	3.66%	902	558	10	913	72
343	Prime Movers	47,504	1,894	45,610	4.58%	2,089	1,214	28	2,117	194
344	Generators	5,821	5	5,815	3.75%	218	(5)	(0)	218	11
345	Accessory Electric Equip.	19,889	30	19,859	4.38%	870	(76)	(2)	868	-
346	Misc. Power Plant Equip.	1,097	-	1,097	4.55%	50	-	-	50	(18)
348	Energy Storage Equipment - Prod	-	-		4.00%		-	-		-
1723 & 1733 TRANSMISSION										
350	Land and Land Rights	-	-	-	0.00%	-	-	-	-	-
351	Clearing Land & Rights of Way	-	-	-	1.54%	-	-	-	-	-
352	Structures & Improvements	-	-	-	2.50%	-	-	-	-	-
353	Station Equipment	-	-	-	3.62%	-	-	-	-	-
354	Towers & Fixtures	-	-	-	1.62%	-	-	-	-	-
355	Poles & Fixtures	-	-	-	2.33%	-	-	-	-	-
356	OH Conductors & Devices	-	-	-	1.75%	-	-	-	-	-
357	Underground Conduit	-	-	-	3.33%	-	-	-	-	-
358	Underground Conduct. & Dev.	-	-	-	3.33%	-	-	-	-	-
359	Roads & Trails	-	-	-	2.50%	-	-	-	-	-
1724 & 1734 DISTRIBUTION										
360	Land and Land Rights	328	-	328	0.00%	-	-	-	-	-
361	Structures & Improvements	810	-	810	2.50%	20	-	-	20	5
362	Station Equipment	1,077	-	1,077	4.00%	43	-	-	43	5
363	Storage Battery Equip.	184	-	184	6.67%	12	-	-	12	(11)
364	Poles & Fixtures	10,238	-	10,238	2.10%	215	(7)	(0)	215	(23)
365	OH Conductors & Devices	3,410	-	3,410	1.91%	65	150	1	67	(6)
366	Underground Conduit	57	-	57	3.33%	2	-	-	2	0
367	Undergrd Conduct. & Devices	244	-	244	3.33%	8	-	-	8	3
368	Line Transformers	4,080	8	4,072	2.00%	81	(11)	(0)	81	(16)
369	Services	1,993	-	1,993	1.91%	38	(2)	(0)	38	(2)
370	Meters	924	-	924	5.56%	51	(76)	(2)	49	15
371	Install. on Cust. Premises	11	-	11	5.56%	1	-	-	1	2
372	Leased Prop. on Cust. Prem.	-	-	-	0.00%	-	-	-	-	-
373	Street Lighting	1,672	-	1,672	2.18%	36	(3)	(0)	36	0
1725 & 1735 GENERAL										
389	Land and Land Rights	221	-	221	0.00%	-	-	-	-	-
390.1	Head Office Building	-	-	-	1.31%	-	-	-	-	-
390.2	Structures & Improvements	7,228	-	7,228	3.77%	272	537	10	283	(166)
391.1	Computers	643	-	643	20.00%	129	(24)	(2)	126	82
391.2	Office Furniture & Equip.	100	-	100	6.00%	6	(2)	(0)	6	(6)
391.3	Software	70	-	70	10.00%	7	-	-	7	1
		-	-	-	0.00%	-	-	-	-	35
392	Transportation Equip.	1,662	34	1,629	11.31%	184	316	18	202	-
393	Stores Equip.	84	-	84	6.67%	6	-	-	6	2
394	Tools, Shop, & Garage Equip.	241	13	228	6.67%	15	(0)	(0)	15	(3)
395	Laboratory Equip.	39	-	39	4.00%	2	-	-	2	-
396	Power Operated Equip.	1,261	-	1,261	3.14%	40	(2)	(0)	40	(7)
397	Communication Equip.	1,999	-	1,999	4.47%	89	(3)	(0)	89	(4)
398	Misc. Equip.	211	-	211	6.67%	14	-	-	14	(4)
399	Other Tangible Property	258	-	258	5.00%	13	-	-	13	1
	Capital Inventory	-	-	-	0.00%	-	-	-	-	
									-	
	Insurance Proceeds	(11,118)	-			(249)			(249)	
	Subtotal Zone Specific	182,356	2,546	190,928		7,094	7,517	144	7,239	368
	Common Cost									
	Corporate								432	79
	Regional								192	(3)
	Distribution Related								71	
	Subtotal Common Cost								695	76
	Total	182,356	2,546	190,928		7,094	7,517	144	7,934	445

CHAPTER 7

RETURN ON RATE BASE

7.0 RETURN ON RATE BASE

The Test Year Return on Rate Base reflects the costs to the Corporation of maintaining capital (long-term debt and equity) to finance assets in service. Table 7.1 sets out the 2016/17, 2017/18 and 2018/19 forecast Return on Rate Base.

Table 7.1
Return on Rate Base – 2013/14 Test Year
Compared to 2016/17-2018/19 Forecasts (000's)

		Test Year		
	2013/14 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Mid-Year Ratebase	297,847	318,753	328,593	330,276
Return on Ratebase				
Average Cost of Debt	6,035	6,715	7,074	6,781
Return on Equity	6,750	7,098	7,032	7,301
Interest Coverage (Thermal)	4,518	4,696	4,751	4,646
Capital Lease	1,839	1,705	1,659	1,612
Total Retun on Rate Base	**19,142**	**20,214**	**20,516**	**20,340**
Average Rate of Return	**6.43%**	**6.34%**	**6.24%**	**6.16%**

From the 2013/14 Test Year to the 2018/19 Test Year the Corporation's Return on Rate Base increased by $1.20 million. The calculation of Return on Rate Base is in accordance with the Board's findings for the 2012/14 GRA. In particular sources of

financing specifically related to certain components of Rate Base are addressed first including long-term debt to finance work-in-progress, and capital lease to be applied 100% to non-thermal assets, leaving "general" capitalization (debt and equity) to finance the remaining components of Rate Base. The calculation of Return on Rate Base for the non-thermal assets includes provisions for debt, equity and the capital lease which is, consistent with past practice. In the thermal zone the ROE has been set to 0% and the effective cost of debt is set to 1.5 times the forecast debt cost rate.

The forecast weighted average cost of capital in the 2013/14 Test Year was 6.43%. In the current GRA, the average cost of capital totals 6.34% in the 2016/17 Test Year, 6.24% in the 2017/18 Test Year and 6.16% in the 2018/19 Test Year.

7.1 RETURN ON EQUITY

The Corporation is proposing a ROE of 8.50% for all three Test Years. NTPC is proposing a simplified approach to setting the ROE to reduce regulatory complexity and costs consistent with the principles set out in the 2009 Creating a Brighter Future Report[1] and the approach used in the 2012/14 GRA. The Corporation notes the requested ROE is similar or lower than other recent industry benchmark ROEs including:

- 9.10% approved 2015 ROE for NUL-NWT.[2]

[1] Efficient, Affordable and Equitable: Creating a Brighter Future for the Northwest Territories' Electricity System.
[2] As shown on Schedule 8.1 of the compliance filing dated October 10, 2014.

- The Alberta Utilities Commission generic ROE for 2015 of 8.3%.[3]
- The long-term target ROE for SaskPower of 8.50% approved by the Crown Investments Corporation.[4]
- The BCUC's approval of a 9.15% ROE for FortisBC (incorporating a 40 basis point risk premium over the benchmark utility ROE of 8.75%).[5]

For the thermal zone, the Corporation has continued to apply an interest coverage ratio of 1.5 in lieu of a return on equity, consistent with the GNWT guidelines.

7.2 COST OF DEBT

The forecast average cost of long-term debt for the Test Years is 5.53% in 2016/17, 5.36% in 2017/18 and 5.26% in 2018/19. This is lower than the average cost of long-term debt for the 2013/14 Test Year (5.68%). This reflects the benefits of refinancing that has occurred since the last GRA and the lower cost of new debt. During the 2018/19 Test Year the Corporation will redeem a 6.33% debenture using proceeds from the sinking fund and internally generated cash. In 2016/17 the Corporation expects to issue a $50 million debenture with semi-annual blended payments of interest and principal. The $50 million debt is forecast to have a 30 year term and uses a rate of

[3] Page 58, AUC Decision 2191-D01-2015.

[4] Per the Minister's terms of reference to the Saskatchewan Rate Review Panel dated October 25, 2013. Available: http://www.saskratereview.ca/images/docs/SaskPower2013/ministers-order-saskpower-rate-change-proposal.pdf

[5] BCUC Order G-47-14.

4.00%. The rate is based on long Canada yields at March 2016 plus a credit spread of between 1.50%-2.00%. Current economic forecasts predict the long Canada yields should remain below the 3% range for the remainder of the fiscal year. The Corporation is in a good position to access longer term debt which will allow it to match the term of the debt to the long asset life.

7.3 CAPITAL LEASE

The costs of the Corporation's capital lease reflect the continuing obligations to the Dogrib Power Corporation in respect of the Snare-Cascades project. The costs and structure of the lease were tested and approved by the PUB and have been applied consistently since the 1995/98 GRA.

7.4 CAPITAL STRUCTURE

The Corporation's proposed capital structure reflects a mixture of between 39-41% equity and 59-61% long-term debt. This is close to the 43% equity 57% debt ratio approved during the Corporation's 2012/14 GRA.[6]

[6] Refer to Schedule 3.5 from the 2012-2014 GRA compliance filing dated March 4, 2013.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
RETURN ON RATE BASE - MID YEAR
(in thousands of dollars)

Line No.		Mid-Year Capitalization	Less Work in Progress and Capital Lease Obligation	General Mid-Year Capitalization	Mid-Year Capital Ratios	Mid-Year Cost Rate All Excluding Thermal Plant Specific	Mid-Year Cost Rate Thermal Plant Specific	Mid-Year Cost Rate Capital Lease Obligation	General Mid-Year Rate Base All Excluding Thermal Plant Specific	General Mid-Year Rate Base Thermal Plant Specific	Capital Lease Obligation	Total Rate Base	Mid-Year Return on Rate Base All Excluding Thermal Plant Specific	Mid-Year Return on Rate Base Thermal Plant Specific	Mid-Year Return on Capital Lease Obligation	Total Mid-Year Return on Rate Base	Total Mid-Year Cost Rate
	2013/14 Forecast																
1	Common Equity	117,737		117,737	43%	8.50%	0.00%		79,414	39,630		117,332	6,750	-		6,750	5.75%
2	Long Term Debt	163,585	5,960	157,625	57%	5.68%	8.51%		106,319	53,056		157,085	6,035	4,518		10,553	6.72%
3	Subtotal: Equity and Debt	281,323		275,363	100%	6.88%	4.87%		185,733	92,685		278,419	12,785	4,518		17,303	6.21%
4	Capital Lease Obligation	19,429	19,429	-	0%		0.00%	9.47%			19,429	19,429	-	-	1,839	1,839	9.47%
5	Total	**300,751**		**275,363**	**100%**	**6.88%**	**4.87%**		**185,733**	**92,685**	**19,429**	**297,847**	**12,785**	**4,518**	**1,839**	**19,142**	**6.43%**
	2013/14 Actual																
6	Common Equity	119,370		119,370	45%	6.20%	0.00%		79,634	38,579		118,213	4,934	-		4,934	4.17%
7	Long Term Debt	164,387	18,642	145,745	55%	5.71%	8.57%		97,229	47,103		144,332	5,556	4,037		9,593	6.65%
8	Subtotal: Equity and Debt	283,756		265,114	100%	5.93%	4.71%		176,863	85,682		262,545	10,490	4,037		14,527	5.53%
9	Capital Lease Obligation	19,395	19,395	-	0%		0.00%	9.47%			19,395	19,395	-	-	1,836	1,836	9.47%
10	Total	**303,151**		**265,114**	**100%**	**5.93%**	**4.71%**		**176,863**	**85,682**	**19,395**	**281,940**	**10,490**	**4,037**	**1,836**	**16,363**	**5.80%**
	2014/15 Actual																
11	Common Equity	121,658		121,658	45%	0.55%	0.00%		81,266	43,643		124,909	444	-		444	0.36%
12	Long Term Debt	162,099	15,637	146,462	55%	5.73%	8.60%		97,835	52,541		150,375	5,610	4,519		10,129	6.74%
13	Subtotal: Equity and Debt	283,757		268,120	100%	3.38%	4.70%		179,101	96,184		275,284	6,054	4,519		10,573	3.84%
14	Capital Lease Obligation	18,990	18,990	-	0%		0.00%	9.44%			18,990	18,990	-	-	1,793	1,793	9.44%
15	**Total**	**302,746**		**268,120**	**100%**	**3.38%**	**4.70%**		**179,101**	**96,184**	**18,990**	**294,274**	**6,054**	**4,519**	**1,793**	**12,366**	**4.20%**
	2015/16 Forecast																
16	Common Equity	120,722		120,722	46%	8.50%	0.00%		84,650	46,396		131,046	7,195	-		7,195	5.49%
17	Long Term Debt	159,786	17,685	142,101	54%	5.77%	8.66%		99,641	54,612		154,253	5,751	4,728		10,479	6.79%
18	Subtotal: Equity and Debt	280,508	17,685	262,823	100%	7.02%	4.68%		184,291	101,008		285,299	12,946	4,728		17,674	6.19%
19	Capital Lease Obligation	18,585	18,585	-	0%			9.43%			18,585	18,585		-	1,752	1,752	9.43%
20	**Total**	**299,093**	**36,270**	**262,823**	**100%**	**7.02%**	**4.68%**	**9.43%**	**184,291**	**101,008**	**18,585**	**303,883**	**12,946**	**4,728**	**1,752**	**19,426**	**6.39%**
	2016/17 Forecast																
21	Common Equity	120,907		120,907	41%	8.50%	0.00%		83,501	38,932		122,433	7,098	-		7,098	5.80%
22	Long Term Debt	182,434	6,514	175,920	59%	5.53%	8.29%		121,495	56,646		178,141	6,715	4,696		11,412	6.41%
23	Subtotal: Equity and Debt	303,341	6,514	296,827	100%	6.74%	4.91%		204,996	95,578		300,574	13,813	4,696		18,509	6.16%
24	Capital Lease Obligation	18,180	18,180	-	0%			9.38%			18,180	18,180		-	1,705	1,705	9.38%
25	**Total**	**321,520**	**24,693**	**296,827**	**100%**	**6.74%**	**4.91%**	**9.38%**	**204,996**	**95,578**	**18,180**	**318,753**	**13,813**	**4,696**	**1,705**	**20,214**	**6.34%**
	2017/18 Forecast																
26	Common Equity	124,021		124,021	39%	8.50%	0.00%		82,726	37,042		119,768	7,032	-		7,032	5.87%
27	Long Term Debt	204,696	6,864	197,833	61%	5.36%	8.04%		131,962	59,088		191,050	7,074	4,751		11,826	6.19%
28	Subtotal: Equity and Debt	328,717	6,864	321,853	100%	6.57%	4.94%		214,688	96,130		310,818	14,106	4,751		18,858	6.07%
29	Capital Lease Obligation	17,775	17,775	-	0%			9.33%			17,775	17,775		-	1,659	1,659	9.33%
30	**Total**	**346,491**	**24,638**	**321,853**	**100%**	**6.57%**	**4.94%**	**9.33%**	**214,688**	**96,130**	**17,775**	**328,593**	**14,106**	**4,751**	**1,659**	**20,516**	**6.24%**
	2018/19 Forecast																
31	Common Equity	129,337		129,337	40%	8.50%	0.00%		85,890	39,235		125,125	7,301	-		7,301	5.83%
32	Long Term Debt	199,879	5,777	194,102	60%	5.26%	7.89%		128,899	58,882		187,781	6,781	4,646		11,427	6.09%
33	Subtotal: Equity and Debt	329,216	5,777	323,439	100%	6.56%	4.74%		214,790	98,117		312,907	14,082	4,646		18,728	5.99%
34	Capital Lease Obligation	17,370	17,370	-	0%			9.28%			17,370	17,370		-	1,612	1,612	9.28%
35	**Total**	**346,586**	**23,147**	**323,439**	**100%**	**6.56%**	**4.74%**	**9.28%**	**214,790**	**98,117**	**17,370**	**330,276**	**14,082**	**4,646**	**1,612**	**20,340**	**6.16%**

Schedule 7.1.1

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
2016/17 Return on Ratebase Calcualtion by Zone

	Snare Zone	Taltson Zone	Thermal Zone	Total
Mid-Year Rate Base				
Plant specific	139,111	22,902	104,221	266,233
Capital Lease	18,180	-	-	18,180
Common cost	12,552	4,026	4,347	20,926
Distribution related common cost	10	18	50	78
Zone-specific Deferral	2,055	6,083	4,575	12,712
Other Deferral and Working Capital	6,448	2,068	2,738	11,254
Less: Customer Contributions	(755)	(1,231)	(8,643)	(10,629)
	177,601	33,865	107,288	318,753
Cost Rate				
Plant specific	6.74%	6.74%	4.91%	6.02%
Capital Lease	9.38%			9.38%
Common cost	6.74%	6.74%	6.74%	6.74%
Distribution related common cost	6.74%	6.74%	6.74%	6.74%
Zone-specific Deferral	6.74%	6.74%	6.74%	6.74%
Other Deferral and Working Capital	6.74%	6.74%	6.74%	6.74%
Less: Customer Contributions	6.74%	6.74%	4.91%	5.25%
Return on Rate Base				
Plant specific	9,373	1,543	5,121	16,038
Capital Lease	1,705	-	-	1,705
Common cost	846	271	293	1,410
Distribution related common cost	1	1	3	5
Zone-specific Deferral	138	410	308	857
Other Deferral and Working Capital	434	139	184	758
Less: Customer Contributions	(51)	(83)	(425)	(559)
Total	**12,447**	**2,282**	**5,485**	**20,214**

Schedule 7.1.2

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
2017/18 Return on Ratebase Calcualtion by Zone

	Snare Zone	Taltson Zone	Thermal Zone	Total
Mid-Year Rate Base				
Plant specific	147,347	23,078	104,197	274,621
Capital Lease	17,775			17,775
Common cost	13,450	4,318	5,358	23,125
Distribution related common cost	97	169	476	742
Zone-specific Deferral	1,693	5,751	4,438	11,882
Other Deferral and Working Capital	6,011	1,930	2,459	10,399
Less: Customer Contributions	(703)	(1,182)	(8,067)	(9,952)
	185,669	34,063	108,861	328,593
Cost Rate				
Plant specific	6.57%	6.57%	4.94%	5.95%
Capital Lease	9.33%			9.33%
Common cost	6.57%	6.57%	6.57%	6.57%
Distribution related common cost	6.57%	6.57%	6.57%	6.57%
Zone-specific Deferral	6.57%	6.57%	6.57%	6.57%
Other Deferral and Working Capital	6.57%	6.57%	6.57%	6.57%
Less: Customer Contributions	6.57%	6.57%	4.94%	5.25%
Return on Rate Base				
Plant specific	9,681	1,516	5,150	16,348
Capital Lease	1,659	-	-	1,659
Common cost	884	284	352	1,519
Distribution related common cost	6	11	31	49
Zone-specific Deferral	111	378	292	781
Other Deferral and Working Capital	395	127	162	683
Less: Customer Contributions	(46)	(78)	(399)	(523)
Total	**12,690**	**2,238**	**5,588**	**20,516**

Schedule 7.1.3

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
2018/19 Return on Ratebase Calcualtion by Zone

	Snare Zone	Taltson Zone	Thermal Zone	Total
Mid-Year Rate Base				
Plant specific	150,123	22,249	105,609	277,981
Capital Lease	17,370	-	-	17,370
Common cost	13,416	4,310	5,951	23,677
Distribution related common cost	244	425	1,193	1,861
Zone-specific Deferral	1,367	5,270	3,060	9,697
Other Deferral and Working Capital	5,209	1,673	2,084	8,966
Less: Customer Contributions	(651)	(1,133)	(7,492)	(9,275)
	187,078	32,794	110,405	330,276
Cost Rate				
Plant specific	6.56%	6.56%	4.74%	5.86%
Capital Lease	9.28%			9.28%
Common cost	6.56%	6.56%	6.56%	6.56%
Distribution related common cost	6.56%	6.56%	6.56%	6.56%
Zone-specific Deferral	6.56%	6.56%	6.56%	6.56%
Other Deferral and Working Capital	6.56%	6.56%	6.56%	6.56%
Less: Customer Contributions	6.56%	6.56%	4.74%	5.09%
Return on Rate Base				
Plant specific	9,842	1,459	5,001	16,302
Capital Lease	1,612	-	-	1,612
Common cost	880	283	390	1,552
Distribution related common cost	16	28	78	122
Zone-specific Deferral	90	346	201	636
Other Deferral and Working Capital	342	110	137	588
Less: Customer Contributions	(43)	(74)	(355)	(472)
Total	**12,738**	**2,150**	**5,452**	**20,340**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
CAPITALIZATION MID-YEAR
(in thousands of dollars)

Schedule 7.2

Line No.		2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	COMMON EQUITY							
1	Opening Balance	114,309	117,103	121,637	121,680	119,764	122,049	125,992
2	Net Income	8,856	4,934	444	-1,516	2,685	4,342	7,090
3	Less: Dividends	2,000	400	400	400	400	400	400
4	Closing Balance	121,165	121,637	121,680	119,764	122,049	125,992	132,682
5	Mid-Year Balance [(L1+L4)/2]	117,737	119,370	121,658	120,722	120,907	124,021	129,337
	DEBT - LONG TERM							
6	Opening Balance	171,235	171,234	169,728	168,176	166,578	215,026	212,633
7	Issue	0	0	0	0	50,000	0	0
8	Repayment	(1,507)	(1,506)	(1,552)	(1,598)	(1,552)	(2,393)	(12,428)
9	Closing Balance	169,727	169,728	168,176	166,578	215,026	212,633	200,205
10	SINKING FUNDS							
11	Opening Balance	6,592	5,676	6,513	7,194	7,988	8,749	9,518
12	Withdrawl for debt repayment	0	0	0	0	0	0	0
13	Contributions, Income & Gains/Losses	606	837	681	794	761	769	(5,956)
14	Closing Balance	7,199	6,513	7,194	7,988	8,749	9,518	3,562
15	Mid-Year Balance [((L6-L11)+(L9-L14)/2]	163,585	164,387	162,099	159,786	182,434	204,696	199,879
	CAPITAL LEASE OBLIGATION							
16	Opening Balance	19,631	19,598	19,192	18,787	18,382	17,977	17,572
17	Additions							
18	Payments	(402)	(406)	(405)	(405)	(405)	(405)	(405)
19	Closing Balance	19,226	19,192	18,787	18,382	17,977	17,572	17,167
20	Mid-Year Balance [(L16+L19)/2]	19,429	19,395	18,990	18,585	18,180	17,775	17,370
	TOTAL MID-YEAR CAPITALIZATION							
21	[L5+L15+L20]	300,751	303,151	302,746	299,093	321,520	346,491	346,586

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
EFFECTIVE COST OF DEBT
(in thousands of dollars)

2013/14 Actual
(thousands of dollars)

Line No.	Loan Number	1	2	3	4	5	6	7	8	TOTAL ALL LOANS
	Loan Amount	$ 8,700	$ 10,000	$ 20,000	$ 25,000	$ 15,000	$ 25,000	$ 50,000	$ 25,000	
1	Interest Rate	8.41%	6.330%	6.420%	5.955%	5.000%	5.443%	5.160%	3.818%	
2	Issue Date	27/Feb/96	27/Oct/98	18/Dec/02	15/Dec/04	16/Dec/05	1/Aug/08	13/Aug/10	1/Apr/12	
3	Opening Balance	8,700	10,000	13,333	25,000	15,000	25,000	49,201	25,000	171,234
4	Issue									0
5	Repayment			666				840		1,506
6	Closing Balance [L3+L4-L5]	8,700	10,000	12,667	25,000	15,000	25,000	48,361	25,000	169,728
7	**Mid-Year Debt Balance (MAD) [(L3+L6)/2]**	**8,700**	**10,000**	**13,000**	**25,000**	**15,000**	**25,000**	**48,781**	**25,000**	**170,481**
8	**Sinking Fund**									
9	Opening Balance	1,690	3,987							5,677
10	Closing Balance	1,997	4,516							6,513
11	**Mid Year Balance (SFI) [(L9+L10)/2]**	**1,844**	**4,252**							**6,095**
12	**DEBT FINANCING COSTS**									
13	Beginning Financing Costs O/S	23	30	694	135	69	112	227	151	1,441
14	Additions									0
15	Less Amortization	2	5	61	6	6	7	8	4	99
16	Ending Financing Costs O/S [L13+L14-L15]	21	25	633	129	64	105	219	147	1,341
17	**Average Financing Costs (UFC) [(L13+L16)/2]**	**22**	**27**	**663**	**132**	**67**	**108**	**223**	**149**	**1,391**
18	**AVERAGE PROCEEDS [L7-L11-L17]**	**6,835**	**5,721**	**12,337**	**24,868**	**14,933**	**24,892**	**48,558**	**24,851**	**162,995**
	INTEREST & AMORTIZATION OF FINANCING COSTS									
19	Interest Expense Amount **(I)** = (L3*L1+L6*L1)/2	732	633	835	1,489	750	1,361	2,517	955	9,270
20	Less: Interest Revenue Amount **(SFE)**	(17)	(39)	0	0					(56)
21	Amortization of Finance Costs **(AFC)**	2	5	61	6	6	7	8	4	99
22	Total Interest and Amortization	716	600	896	1,495	756	1,368	2,525	958	9,314
	EFFECTIVE COST OF LONG TERM DEBT	**10.48%**	**10.48%**	**7.26%**	**6.01%**	**5.06%**	**5.50%**	**5.20%**	**3.86%**	**5.71%**
23	**(I+AFC-SFE)/(MAD - UFC - SFI)**									

Schedule 7.3

2014/15 Actual
(thousands of dollars)

Line No.	Loan Number / Loan Amount / Interest Rate / Issue Date	1 $ 8,700 8.41% 27/Feb/96	2 $ 10,000 6.330% 27/Oct/98	3 $ 20,000 6.420% 18/Dec/02	4 $ 25,000 5.955% 15/Dec/04	5 $ 15,000 5.000% 16/Dec/05	6 $ 25,000 5.443% 1/Aug/08	7 $ 50,000 5.160% 13/Aug/10	8 $ 25,000 3.818% 1/Apr/12		TOTAL ALL LOANS
3	Opening Balance	8,700	10,000	12,667	25,000	15,000	25,000	48,361	25,000		169,728
4	Issue										0
5	Repayment			667				885			1,552
6	Closing Balance [L3+L4-L5]	8,700	10,000	12,000	25,000	15,000	25,000	47,476	25,000		168,176
7	**Mid-Year Debt Balance (MAD) [(L3+L6)/2]**	**8,700**	**10,000**	**12,334**	**25,000**	**15,000**	**25,000**	**47,919**	**25,000**		**168,952**
8	**Sinking Fund**										
9	Opening Balance	1,997	4,516								6,513
10	Closing Balance	2,304	4,890								7,194
11	**Mid Year Balance (SFI) [(L9+L10)/2]**	**2,151**	**4,703**								**6,854**
12	**DEBT FINANCING COSTS**										
13	Beginning Financing Costs O/S	21	25	633	129	64	105	219	147		1,341
14	Additions										0
15	Less Amortization	2	5	58	6	6	7	8	4		97
16	Ending Financing Costs O/S [L13+L14-L15]	19	19	575	123	58	97	210	143		1,245
17	**Average Financing Costs (UFC) [(L13+L16)/2]**	**20**	**22**	**604**	**126**	**61**	**101**	**215**	**145**		**1,293**
18	**AVERAGE PROCEEDS [L7-L11-L17]**	**6,529**	**5,275**	**11,730**	**24,874**	**14,939**	**24,899**	**47,704**	**24,855**		**160,806**
	INTEREST & AMORTIZATION OF FINANCING COSTS										
19	Interest Expense Amount **(I)** = (L3*L1+L6*L1)/2	732	633	792	1,489	750	1,361	2,473	955		9,183
20	Less: Interest Revenue Amount **(SFE)**	(19)	(40)	0	0						(59)
21	Amortization of Finance Costs **(AFC)**	2	5	58	6	6	7	8	4		97
22	Total Interest and Amortization	715	598	850	1,495	756	1,368	2,481	958		9,221
	EFFECTIVE COST OF LONG TERM DEBT	**10.94%**	**11.34%**	**7.25%**	**6.01%**	**5.06%**	**5.49%**	**5.20%**	**3.86%**		**5.73%**
23	**(I+AFC-SFE)/(MAD - UFC - SFI)**										

Schedule 7.3

2015/16 Forecast
(thousands of dollars)

Line No.	Loan Number / Loan Amount / Interest Rate / Issue Date	1 $ 8,700 8.41% 27/Feb/96	2 $ 10,000 6.330% 27/Oct/98	3 $ 20,000 6.420% 18/Dec/02	4 $ 25,000 5.955% 15/Dec/04	5 $ 15,000 5.000% 16/Dec/05	6 $ 25,000 5.443% 1/Aug/08	7 $ 50,000 5.160% 13/Aug/10	8 $ 25,000 3.818% 1/Apr/12		TOTAL ALL LOANS
3	Opening Balance	8,700	10,000	12,000	25,000	15,000	25,000	47,476	25,000		168,176
4	Issue										0
5	Repayment			667				931			1,598
6	Closing Balance [L3+L4-L5]	8,700	10,000	11,333	25,000	15,000	25,000	46,545	25,000		166,578
7	**Mid-Year Debt Balance (MAD) [(L3+L6)/2]**	**8,700**	**10,000**	**11,667**	**25,000**	**15,000**	**25,000**	**47,011**	**25,000**		**167,377**
8	**Sinking Fund**										
9	Opening Balance	2,304	4,890								7,194
10	Closing Balance	2,604	5,384								7,988
11	**Mid Year Balance (SFI) [(L9+L10)/2]**	**2,454**	**5,137**								**7,591**
12	**DEBT FINANCING COSTS**										
13	Beginning Financing Costs O/S	19	19	575	123	58	97	210	143		1,245
14	Additions										0
15	Less Amortization	2	5	56	6	6	7	8	4		94
16	Ending Financing Costs O/S [L13+L14-L15]	17	14	519	116	52	90	202	140		1,150
17	**Average Financing Costs (UFC) [(L13+L16)/2]**	**18**	**16**	**547**	**119**	**55**	**94**	**206**	**141**		**1,197**
18	**AVERAGE PROCEEDS [L7-L11-L17]**	**6,228**	**4,847**	**11,120**	**24,881**	**14,945**	**24,906**	**46,804**	**24,859**		**158,589**
	INTEREST & AMORTIZATION OF FINANCING COSTS										
19	Interest Expense Amount **(I)** = (L3*L1+L6*L1)/2	732	633	749	1,489	750	1,361	2,426	955		9,093
20	Less: Interest Revenue Amount **(SFE)**	(11)	(24)	0	0						(35)
21	Amortization of Finance Costs **(AFC)**	2	5	56	6	6	7	8	4		94
22	Total Interest and Amortization	722	615	805	1,495	756	1,368	2,434	958		9,153
	EFFECTIVE COST OF LONG TERM DEBT	**11.60%**	**12.68%**	**7.24%**	**6.01%**	**5.06%**	**5.49%**	**5.20%**	**3.86%**		**5.77%**
23	**(I+AFC-SFE)/(MAD - UFC - SFI)**										

Schedule 7.3

2016/17 Forecast
(thousands of dollars)

Line No.		1	2	3	4	5	6	7	8	9	
	Loan Number										
	Loan Amount	$ 8,700	$ 10,000	$ 20,000	$ 25,000	$ 15,000	$ 25,000	$ 50,000	$ 25,000	$ 50,000	**TOTAL**
1	Interest Rate	8.41%	6.330%	6.420%	5.955%	5.000%	5.443%	5.160%	3.818%	4.000%	**ALL**
2	Issue Date	27/Feb/96	27/Oct/98	18/Dec/02	15/Dec/04	16/Dec/05	1/Aug/08	13/Aug/10	1/Apr/12	1/Dec/16	**LOANS**
3	Opening Balance	8,700	10,000	11,333	25,000	15,000	25,000	46,545	25,000	0	166,578
4	Issue									50,000	50,000
5	Repayment			667				885			1,552
6	Closing Balance [L3+L4-L5]	8,700	10,000	10,666	25,000	15,000	25,000	45,660	25,000	50,000	215,026
7	**Mid-Year Debt Balance (MAD) [(L3+L6)/2]**	**8,700**	**10,000**	**11,000**	**25,000**	**15,000**	**25,000**	**46,103**	**25,000**	**25,000**	**190,802**
8	**Sinking Fund**										
9	Opening Balance	2,604	5,384								7988
10	Closing Balance	2,920	5,829								8749
11	**Mid Year Balance (SFI) [(L9+L10)/2]**	**2,762**	**5,607**								8368.5
12	**DEBT FINANCING COSTS**										
13	Beginning Financing Costs O/S	17	14	519	116	52	90	202	140		1,150
14	Additions									245	245
15	Less Amortization	2	5	53	6	6	7	8	4	3	94
16	Ending Financing Costs O/S [L13+L14-L15]	16	8	466	110	47	83	194	136	242	1,301
											0
17	**Average Financing Costs (UFC) [(L13+L16)/2]**	**17**	**11**	**492**	**113**	**50**	**86**	**198**	**138**	**121**	**1,226**
											0
18	**AVERAGE PROCEEDS [L7-L11-L17]**	**5,921**	**4,383**	**10,507**	**24,887**	**14,950**	**24,914**	**45,905**	**24,862**	**24,879**	**181,208**
	INTEREST & AMORTIZATION OF FINANCING COSTS										
19	Interest Expense Amount **(I)** = (L3*L1+L6*L1)/2	732	633	706	1,489	750	1,361	2,379	955	1,000	10,004
20	Less: Interest Revenue Amount **(SFE)**	(27)	(55)	0							(82)
21	Amortization of Finance Costs **(AFC)**	2	5	53	6	6	7	8	4	3	94
22	Total Interest and Amortization	706	584	759	1,495	756	1,368	2,387	958	1,003	10,016
	EFFECTIVE COST OF LONG TERM DEBT	**11.93%**	**13.31%**	**7.22%**	**6.01%**	**5.05%**	**5.49%**	**5.20%**	**3.85%**	**4.03%**	**5.53%**
23	**(I+AFC-SFE)/(MAD - UFC - SFI)**										

Schedule 7.3

2017/18 Forecast
(thousands of dollars)

Line No.	Loan Number / Loan Amount / Interest Rate / Issue Date	1 $ 8,700 8.41% 27/Feb/96	2 $ 10,000 6.330% 27/Oct/98	3 $ 20,000 6.420% 18/Dec/02	4 $ 25,000 5.955% 15/Dec/04	5 $ 15,000 5.000% 16/Dec/05	6 $ 25,000 5.443% 1/Aug/08	7 $ 50,000 5.160% 13/Aug/10	8 $ 25,000 3.818% 1/Apr/12	9 $ 50,000 4.000% 1/Dec/16	TOTAL ALL LOANS
3	Opening Balance	8,700	10,000	10,666	25,000	15,000	25,000	45,660	25,000	50,000	215,026
4	Issue										0
5	Repayment			667				840		886	2,393
6	Closing Balance [L3+L4-L5]	8,700	10,000	9,999	25,000	15,000	25,000	44,820	25,000	49,114	212,633
7	**Mid-Year Debt Balance (MAD) [(L3+L6)/2]**	**8,700**	**10,000**	**10,333**	**25,000**	**15,000**	**25,000**	**45,240**	**25,000**	**49,557**	**213,830**
8	**Sinking Fund**										
9	Opening Balance	2,920	5,829								8749
10	Closing Balance	3,239	6,279								9518
11	**Mid Year Balance (SFI) [(L9+L10)/2]**	**3,080**	**6,054**								9133.5
12	**DEBT FINANCING COSTS**										
13	Beginning Financing Costs O/S	16	8	466	110	47	83	194	136	242	1,301
14	Additions										0
15	Less Amortization	2	5	50	6	6	7	8	4	8	97
16	Ending Financing Costs O/S [L13+L14-L15]	14	3	416	104	41	75	186	132	234	1,205
											0
17	**Average Financing Costs (UFC) [(L13+L16)/2]**	**15**	**5**	**441**	**107**	**44**	**79**	**190**	**134**	**238**	**1,253**
											0
18	**AVERAGE PROCEEDS [L7-L11-L17]**	**5,606**	**3,941**	**9,892**	**24,893**	**14,956**	**24,921**	**45,050**	**24,866**	**49,319**	**203,443**
	INTEREST & AMORTIZATION OF FINANCING COSTS										
19	Interest Expense Amount **(I)** = (L3*L1+L6*L1)/2	732	633	663	1,489	750	1,361	2,334	955	1,982	10,899
20	Less: Interest Revenue Amount **(SFE)**	(30)	(59)								(89)
21	Amortization of Finance Costs **(AFC)**	2	5	50	6	6	7	8	4	8	97
22	Total Interest and Amortization	703	580	713	1,495	756	1,368	2,343	958	1,991	10,906
	EFFECTIVE COST OF LONG TERM DEBT	**12.54%**	**14.71%**	**7.21%**	**6.01%**	**5.05%**	**5.49%**	**5.20%**	**3.85%**	**4.04%**	**5.36%**
23	**(I+AFC-SFE)/(MAD - UFC - SFI)**										

Schedule 7.3

2018/19 Forecast
(thousands of dollars)

Line No.	Loan Number	1	2	3	4	5	6	7	8	9	
	Loan Amount	$ 8,700	$ 10,000	$ 20,000	$ 25,000	$ 15,000	$ 25,000	$ 50,000	$ 25,000	$ 50,000	TOTAL
1	Interest Rate	8.41%	6.330%	6.420%	5.955%	5.000%	5.443%	5.160%	3.818%	4.000%	ALL
2	Issue Date	27/Feb/96	27/Oct/98	18/Dec/02	15/Dec/04	16/Dec/05	1/Aug/08	13/Aug/10	1/Apr/12	1/Dec/16	LOANS
3	Opening Balance	8,700	10,000	9,999	25,000	15,000	25,000	44,820	25,000	49,114	212,633
4	Issue										0
5	Repayment		10,000	667				840		921	12,428
6	Closing Balance [L3+L4-L5]	8,700	0	9,333	25,000	15,000	25,000	43,980	25,000	48,193	200,205
7	**Mid-Year Debt Balance (MAD) [(L3+L6)/2]**	**8,700**	**5,000**	**9,666**	**25,000**	**15,000**	**25,000**	**44,400**	**25,000**	**48,654**	**206,419**
8	**Sinking Fund**										
9	Opening Balance	3,239	6,279								9518
10	Closing Balance	3,562	0								3562
11	**Mid Year Balance (SFI) [(L9+L10)/2]**	**3,401**	**3,140**								6540
12	**DEBT FINANCING COSTS**										
13	Beginning Financing Costs O/S	14	3	416	104	41	75	186	132	234	1,205
14	Additions										0
15	Less Amortization	2	3	47	6	6	7	8	4	8	91
16	Ending Financing Costs O/S [L13+L14-L15]	12	0	369	98	35	68	177	128	226	1,113
											0
17	**Average Financing Costs (UFC) [(L13+L16)/2]**	**13**	**1**	**392**	**101**	**38**	**72**	**181**	**130**	**230**	**1,159**
											0
18	**AVERAGE PROCEEDS [L7-L11-L17]**	**5,287**	**1,859**	**9,274**	**24,899**	**14,962**	**24,928**	**44,218**	**24,870**	**48,424**	**198,720**
	INTEREST & AMORTIZATION OF FINANCING COSTS										
19	Interest Expense Amount **(I)** = (L3*L1+L6*L1)/2	732	317	621	1,489	750	1,361	2,291	955	1,946	10,460
20	Less: Interest Revenue Amount **(SFE)**	(97)	0								(97)
21	Amortization of Finance Costs **(AFC)**	2	3	47	6	6	7	8	4	8	91
22	Total Interest and Amortization	636	319	668	1,495	756	1,368	2,299	958	1,954	10,454
	EFFECTIVE COST OF LONG TERM DEBT	**12.04%**	**17.17%**	**7.20%**	**6.00%**	**5.05%**	**5.49%**	**5.20%**	**3.85%**	**4.04%**	**5.26%**
23	**(I+AFC-SFE)/(MAD - UFC - SFI)**										

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Net Earnings Calculation
($000s)

Line No.	Description	2013/14 Actual	2014/15 Actual	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	Revenues						
1	Sales revenues at Existing Rates	101,034	100,061	99,832	100,201	100,389	100,396
2	Sales revenues from interim rates				3,746	8,420	12,504
3	Other revenue	1,174	1,498	1,617	1,714	1,714	1,714
4	**Total Revenues**	102,208	101,559	101,449	105,660	110,523	114,614
	Expenses						
5	Non-Production Fuel O&M	38,536	41,911	42,786	42,185	43,372	44,023
6	Production Fuel Expense	27,985	27,166	26,237	23,400	23,912	24,360
7	Amortization Expense	19,324	20,115	20,825	24,273	25,412	26,102
8	LTD interest expense and allowance for interest coverage	11,429	11,922	13,116	13,116	13,485	13,039
9	**Subtotal**	97,274	101,115	102,965	102,975	106,180	107,524
10	Earnings prior to Return on Equity	4,934	444	(1,516)	2,685	4,342	7,090
11	**Test Year Full Return on Equity**				**7,098**	**7,032**	**7,301**
12	**Return on Equity Shortfall**				**(4,412)**	**(2,689)**	**(210)**

CHAPTER 8

INCOME TAXES

8.0 INCOME TAXES

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as this Schedule is not Applicable to NTPC

Schedule 8.0

CHAPTER 9

OTHER TAXES

9.0 OTHER TAXES

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Schedule 9.0

CHAPTER 10

OTHER REVENUES

10.0 OTHER REVENUES

Other revenues are an offset to the Corporation's Revenue Requirement from non-electrical sources of revenue. Detailed non-electrical revenue by years since the 2012/14 GRA is provided in Schedule 10.0.

Other revenue is forecast at $1.714 million for all Test Years (2016/17 to 2018/19). Table 10.1 provides the comparison of the other revenues forecast to the 2013/14 Test Year by component.

Table 10.1

Other Revenues Forecast

	2013/14 Forecast	2016/17 Forecast	*Change*
Connection Charges	253	235	*(18)*
Contract Work	295	360	*65*
Pole Rental	280	267	*(13)*
Heat Revenue	43	520	*477*
Interruptible Heat Sales	113	154	*41*
User Pay Fees	74	110	*36*
Interest on Overdue Accounts		68	*68*
Total	**1,058**	**1,714**	***656***

Forecast other revenues have increased by $0.656 million (62%) in the 2016/17 test year compared to the 2013/14 test year. This increase is mainly driven by higher residual heat revenue and the inclusion of interest on overdue accounts.

Interest on overdue accounts is forecast at $0.068 million for the 2016/17 Test Year and has been added to the other revenues consistent with the Board Directive 29 from Decision 1-2013.

Residual heat sales revenue forecast has increased by $0.477 million as compared to the 2013/14 forecast. This increase is related to the revenue from residual heat sales to the Inuvik Water Treatment Plant. In the past heat sales to this plant were based on a flat rate of $0.040 million annually. In 2014/15 the Corporation installed a meter for heat sales at the plant and began billing based on a metered rate.

The revenue forecast has also increased in all other components, except Connection Charges and Pole Rental, where it has slightly decreased ($0.018 million and $0.013 million, respectively).

The breakout of the other revenue forecast by component and zone for 2016/17 compared to the 2013/14 Test Year is set out in Table 10.2.

Table 10.2

Other Revenues Forecast by Zone

	Snare			Tatson			Thermal		
	2013/14 Forecast	2016/17 Forecast	*Change*	2013/14 Forecast	2016/17 Forecast	*Change*	2013/14 Forecast	2016/17 Forecast	*Change*
Connection Charges	20	20	*(0)*	45	43	*(2)*	187	172	*(15)*
Contract Work	14	18	*3*	3	4	*1*	278	339	*61*
Pole Rental	31	28	*(3)*	40	40	*(0)*	210	200	*(10)*
Heat Revenue		-	-		-	-	43	520	*477*
Interruptible Heat Sales		-		113	154	*41*		-	
User Pay Fees	9	13	*4*	8	12	*4*	57	85	*28*
Interest on Overdue Accounts		40	*40*		13	*13*		16	*16*
Total	**74**	**118**	***44***	**208**	**264**	***56***	**775**	**1,332**	***557***

Total other revenue forecast by zone has increased for each zone. The revenue forecast growth for Taltson zone is explained by higher interruptible heat sales, reflecting the addition of new customers, and the inclusion of interest on overdue accounts in other revenues. Similarly, the main drivers of the forecast revenue increase for Thermal zone are heat revenue due to switching to a metered rate for the Inuvik Water Treatment Plant and the inclusion of interest on overdue accounts, as well as the growth in user pay fees.

Other revenue forecast methods for the Test Years are explained below:

- **Connection charges:** Forecast is based on a review of the actual revenues for the past 3 years.

- **Contract work:** Forecast is based on a review of the actual revenues for the past 3 years.

- **Pole rental revenue:** Forecast is based on the review of existing and expected connections for joint use of poles.

- **Heat revenue:** Forecasts for the Test Years reflect higher sales due to metering sales to the Inuvik Water Treatment Plant and a 3-year actual average for other facilities.

- **Interruptible heat sales:** Forecasts for the Test Years are based on 3-year actual average, revenue from new customers and rates set as per the existing contracts for Fort Smith heat sales.

- **User pay fees:** Forecast is based on expected revenue from existing user pay customers.

- **Interest on overdue accounts:** Forecast is based on a review of the actual revenues for the past 3 years.

Schedule 10.0

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Non-Electric Revenues
(in thousands of dollars)

	2013/14 Forecast	2013/14 Actual	*Year over Year Change*	2014/15 Actual	*Year over Year Change*	2015/16 Forecast	*Year over Year Change*	2016/17 Forecast	*Year over Year Change*	2017/18 Forecast	*Year over Year Change*	2018/19 Forecast
Connection Charges	253	265	*76*	341	*(71)*	270	*(35)*	235	-	235	-	235
Contract Work	295	228	*110*	338	*165*	503	*(143)*	360	-	360	-	360
Pole Rental	280	270	*3*	273	*19*	292	*(25)*	267	-	267	-	267
Heat Revenue	43	106	*293*	399	*(139)*	260	*260*	520	-	520	-	520
Interruptible Heat Sales	113	19	*34*	52	*44*	96	*58*	154	-	154	-	154
User Pay Fees	74		-		*110*	110	-	110	-	110	-	110
Misc Income	0	207	*(112)*	95	*(95)*	0	-		-		-	
Interest on Overdue Accounts								68		68		68
GNWT Funding	0	79	*(79)*		*85*	85	*(85)*		-		-	
Total	**1,058**	**1,174**	*324*	**1,498**	*119*	**1,617**	*97*	**1,714**	-	**1,714**	-	**1,714**

CHAPTER 11

RATE BASE

11.0 RATE BASE

This chapter sets out the calculation of the Corporation's mid-year Rate Base for the 2016/17, 2017/18 and 2018/19 Test Years. Specifically the chapter deals with the following topics:

- Plant in service including gross plant, accumulated amortization and customer contributions
- Additions to plant since the last GRA and in the Test Years
- Necessary working capital
- Deferred expenses and deferral accounts

The calculation of the Corporation's mid-year Rate Base is set out in Schedule 11.0. Mid-year Rate Base is forecast to increase from $297.9 million in the 2013/14 Test Year to $318.8 million in 2016/17, $328.6 million in 2017/18 and $330.3 million in 2018/19. These increases result primarily from increases in net plant in service through capital investment.

11.1 PLANT IN SERVICE

This section summarizes the calculation of net plant in service since the previous GRA including forecasts for the Test Years. This section includes a discussion of:

- Gross plant in service
- Accumulated amortization
- Customer contributions

Gross Plant in Service

Gross plant in service represents the accounting cost of all regulated NTPC assets in service. Each year the Rate Base calculation considers the opening balance, plus capital additions less disposals to arrive at the closing balance for the year. The mid-year gross plant figures are the simple average of the Opening Gross Plant Balance and the Ending Gross Plant Balance. Gross plant in service calculations for 2013/14 through 2018/19 are set out in Schedule 11.1. Table 11.1 summarizes the changes to gross plant in service from the 2013/14 Test Year to the 2016/17 Test Year.

Table 11.1
Comparison of 2013/14 Test Year Closing Gross Plant and 2016/17 Forecast Closing Gross Plant ($000)

Gross Plant by Function	2013/14 Forecast	2016/17 Forecast	Increase
Hydro Plant	166,981	181,591	14,610
Thermal Plant	161,888	188,594	26,706
Transmission Plant	50,134	55,655	5,521
Distribution Plant	34,001	38,354	4,353
General Plant	55,328	55,734	406
EUG Plant	5,924	11,385	5,461
less: Insurance Proceeds	(13,139)	(13,139)	-
Total	461,117	518,174	57,057

Forecast 2016/17 gross plant in service increased by approximately $57 million as compared to the 2013/14 Test Year, an average annual increase of approximately 4.12%. The largest component of this increase from the 2013/14 Test Year is additions to the thermal plant including the Inuvik LNG project. Investment in alternative energy projects such as solar and heat recovery account for $5.4 million and hydro plant investment accounts for $14.6 million. Detailed discussion of the forecast capital additions is provided in section 11.2.

Accumulated Amortization

Accumulated amortization represents the collected amortization for all regulated NTPC assets in service. Each year the accumulated amortization calculation considers the opening balance, plus amortization expense and amortization reserve variance less

disposals and site restoration spending to arrive at the ending balance for the year. Accumulated amortization calculation also includes an annual true-up provision and net salvage, if applicable. The mid-year accumulated amortization figures are the simple average of the Opening Accumulated Amortization Balance and the Ending Accumulated Amortization Balance. Accumulated amortization calculations for 2013/14 through 2018/19 are set out in Schedule 11.2. A comparison of accumulated amortization between the 2013/14 Test Year and the 2016/17 Test Year is provided in Table 11.2.

Table 11.2

Comparison of 2013/14 Test Year and 2016/7 Test Year Forecast
Closing Accumulated Amortization ($000)

Accumulated Amortization by Function	2013/14 Forecast	2016/17 Forecast	Increase
Hydro Plant	35,380	42,266	6,886
Thermal Plant	72,937	85,210	12,273
Transmission Plant	28,018	31,625	3,607
Distribution Plant	20,750	22,492	1,742
General Plant	20,358	26,975	6,617
EUG Plant	2,596	3,001	405
less: Insurance Proceeds	(7,544)	(8,411)	(867)
Total	172,495	203,157	30,662

Accumulated amortization is forecast to increase by approximately $30.6 million compared to the 2013/14 Test Year. The change includes continued amortization of the Corporation's assets at the rates approved by the Board and where changes are proposed to the current rates in the Application, at the rates proposed.

Net Plant In Service

The Corporation's Rate Base incorporates Net Plant in Service which is calculated as Gross Plant in Service less Accumulated Amortization. Table 11.3 compares the Net Plant in Service between the 2013/14 Test Year and 2016/17 Test Year.

Table 11.3
Comparison of 2014 Test Year and 2017 Test Year Forecast
Closing Net Plant ($000)

Net Plant by Function	2013/14 Forecast	2016/17 Forecast	Increase
Hydro Plant	131,601	139,325	7,724
Thermal Plant	88,951	103,384	14,433
Transmission Plant	22,116	24,030	1,914
Distribution Plant	13,251	15,863	2,612
General Plant	34,970	28,759	(6,211)
EUG Plant	3,328	8,385	5,057
less: Insurance Proceeds	(5,595)	(4,728)	867
Total	288,622	315,017	26,395

The table indicates the largest change in Net Plant in Service occurred in Thermal Plant ($14.4 million) mainly reflecting the capitalization of the Inuvik LNG project. The average annual growth of Net Plant in Service is 3.05%. Additions to alternative energy such as solar generation added $5 million to Net Plant in Service.

Customer Contributions

Net mid-year Customer Contributions are the portion of assets that were recovered directly from the Corporation's customers at the time the asset was constructed. Net

mid-year Customer Contributions are deducted from the calculation of Rate Base so the cost of these assets, are not recovered twice from customers. Calculation of Net mid-year Customer Contributions for 2013/14 Test Year through 2018/19 Test Year are set out in Schedule 11.3. Net mid-year Customer Contributions have increased by approximately $4 million from 2013/14 to 2016/17 reflecting additional support from the GNWT for alternative energy projects to the benefit of customers.

11.2 ADDITIONS TO PLANT

NTPC Capital Planning Process

The NTPC capital planning process supports the orderly replacement of aging infrastructure and provides effective management of NTPC assets on a community wide basis. This process prioritizes the Corporation's assets for replacement, thereby ensuring the Corporation's asset base is able to deliver reliable power generation to meet the needs of its customers. An effective capital planning process is essential to ensure the continued long term viability of the Corporation. Therefore, the Corporation has developed a comprehensive capital planning process that will allow it to achieve its strategic objectives and deliver reliable power generation to its customers.

The Asset Management and Engineering Division (AME) oversee the capital planning process. An overview of the capital planning process is outlined below.

Capital Project Initiation & Approval Phase:

Potential capital projects can be initiated for review by Engineering Asset Managers (AME Division) or Project Sponsors (Divisional Director of Operations and/or Operations Managers).

AME Asset Managers complete risk assessments of the existing asset base using a methodology based on condition assessment and risk of failure. The condition assessment establishes the current state (health) of the asset, while the risk of failure measure is determined by the consequence of failure and the frequency of failure. Assets are assigned numerical value derived from the condition rating. Projects are identified and prioritized according to the numerical value assigned to the asset to be replaced. The selected projects are submitted to the Director of AME for approval to move the project forward to the next step in the Capital Project Initiation Phase, which requires completion of a project brief. This brief is prepared by the AME Asset Manager and it outlines the project options, scope, resources, budget estimates and scheduling.

Project sponsors identify and initiate potential projects based on operational requirements and known asset issues. Project sponsors can be from any company division (Thermal, Hydro, Finance, Information Technology, etc). These sponsored projects are reviewed by the AME Managers and submitted to the Director of AME for approval to proceed to the next step of completing a project brief.

Once the project brief is completed, projects with a capital budget over $400,000 are sent to the Finance Division for review and business case preparation. The project briefs for projects under $400,000 are sent back to the Asset Manager or Project

Sponsor for review. If the Asset Manager/Sponsor deems the project brief acceptable, the project is then included in the 5 year Capital Program.

All new projects under $400,000 but greater than $100,000, as well as replacement projects less than $1,000,000, are reviewed by Senior Management and approved or declined. The Capital Program is then amended if required to include the approved projects or remove declined projects. Projects under $100,000 are submitted for approval to the Director of AME and Chief Financial Officer (CFO).

Senior Management reviews all business cases (budget greater than $400,000) and decides which projects are acceptable. All approved business cases are then submitted to the Board of Directors (BOD) for approval. The BOD approved projects are included in the Corporation's BOD approved Capital Program, with projects under $5,000,000 moving to the design phase. Projects greater than $5,000,000 are submitted to the PUB for approval, and proceed to the design phase if approved by the PUB.

Design Phase:

Projects included in the BOD approved capital program are allocated to the NTPC Engineering Design Group to complete the project design. The Design Group may engage the Logistics Group or an external consultant if necessary depending on the nature and size of the project.

A detailed project scope is developed outlining the impacts the project will have on NTPC systems. The operational directors/managers review the project scope and determine whether it is satisfactory or needs to be revised.

It is then determined whether NTPC or an external consultant will design the project. The project design is then finalized, complete with drawings, specifications and financial forecasts.

The completed project design package is reviewed by the Engineering Asset Managers and the applicable Divisional Directors/Managers (e.g. Technical Services, Hydro, Thermal, Finance). Once the project design is approved by the internal stakeholders, a construction cost estimate is completed with the assistance of the Logistics Group (if required). The construction cost estimate is updated in the capital plan and submitted to the BOD for approval. Long lead time materials are ordered to coincide with the project completion schedule.

Project Execution/Management Phase:

Once the design phase is completed, the project moves to the project execution and management phase. The project proceeds to the Project Management Group and is assigned to a Project Manager. This manager develops a project management plan and prepares the project for procurement.

The procurement process involves the establishment of the procurement format (public, invitational, sole source, request for proposal). The process includes the completion of a safety review, environmental review and request to bid form. The procurement results are reviewed and evaluated using a composite rating based on a number of evaluation criteria (cost, experience, methodology, track record of the technology, safety, etc.). The bidder with the highest composite rating is awarded the contract.

The construction process begins upon awarding the contract to the successful bidder. The project construction process includes the following main elements: daily reports from the construction supervisor, review of tailboards, weekly/monthly reports issued by the Project Manager to internal stakeholders, monthly financial forecast, payment approval, inspections, testing and commissioning, and the issuance of a substantial completion report.

In the event of a change of project scope that results in an increase in the cost of the project, the Project Management Group completes a Job Cost Revision (JCR) that provides a detailed breakdown of the revised project costs. The JCR is reviewed by the project Asset Manager to ensure the increase in project cost is reasonable and that proceeding with the project is the most cost effective option. Projects with cost revisions less than $100,000 are reviewed by the Project Manager, Divisional Director, Director of AME and the CFO. All cost revisions greater than $100,000 must be reviewed and approved by Senior Management. If the revision is greater than $250,000, the JCR must also be approved and signed by the CEO. Scope changes that result in a greater than 10% increase in the project costs for BOD approved projects are submitted to the BOD for approval.

Once project construction ends, post construction procedures are undertaken to create operation and maintenance manuals, enter project data into the Computerized Maintenance Management System (CMMS), prepare post construction report and complete fixed asset and financial close outs. The project is fully completed once the post construction procedures are carried out.

The AME Asset Manager reviews the success of projects that cost more than $400,000 to complete. Project Sponsors are notified of the projects status/success and the AME Asset Manager issues a final report to Senior Management.

Capital Addition Summary

This section is a summary of actual capital spending for 2014/15 forecast for 2015/16, as well as Test Year forecasts for 2016/17, 2017/18 and 2018/19. The Corporation has provided additional detail for projects over $400,000 including the projects previously approved by the PUB through Major Project Permit Applications.

11.2.1 Actual Capital Projects for 2014/15 Over $400,000

The following is a summary description of the capital additions for all projects with a budget over $400,000 for 2014/15. A variance explanation has been provided where the actual total capital additions were above or below total budget by $200,000.

Snare Zone:

Snare System Transient Stability Upgrade

2014/15 Capital Addition: $2,283,000 Total Budget: $3,264,000

This is year two of two of a multi-year project that began in 2013/14. This capital project was undertaken to upgrade the governor system to a digital system to improve stability of the Snare hydro system. The Corporation upgraded the Snare Forks and Snare Falls governors to digital units. In addition, a system integration study and protection coordination study were completed to correct frequency stability issues. The total

project spend of $3.645 million was above the original total budget of $3.264 million due to additional site services costs.

North Slave Two Megawatt Mobile Diesel Generator

2014/15 Capital Addition: $1,366,000 Total Budget: $1,600,000

This is year one of two of a multi-year project. This project consisted of purchasing a two megawatt mobile diesel generator for the Jackfish power plant in Yellowknife. The new generator provided an immediate increase to the available capacity of the Snare-Yellowknife system. The low water event on the Snare hydro system required the Jackfish facility to be run on a continuous basis and increased the probability of failure of the existing generators. The mobile genset provides backup power generation in the event of a failure of the older generators. The total project spend of $1.505 million was slightly below the original total budget of $1.600 million.

Duncan Dam Upgrades

2014/15 Capital Addition: $457,000 Total Budget: $537,000

This project entailed the replacement of the existing timber decking on the Duncan Dam structure at the Bluefish hydro facility. In addition, the aging steel frame and wooden stoplogs were replaced with a more modern and efficient lifting structure and aluminum stoplogs. The deterioration of the structure was causing performance and safety issues that needed to be addressed. The spillway is a vital structure at the dam and allows for the control of water flows on the Bluefish system. The total project spend of $0.457 million was below the original total budget of $0.537 million.

North Slave Protective Relay Upgrades

2014/15 Capital Addition: $416,000 Total Budget: $3,499,000

This is year one of three of a multi-year project. This project was undertaken to replace obsolete electromechanical relays with new electronic relays for the North Slave system. It was expensive and more operationally challenging to maintain obsolete relays, which had the additional need for periodic calibration. The new relays require less maintenance and provide better system protection thereby increasing the reliability of the North Slave power system. The total project spend of $0.875 million was significantly below the original total budget of $3.499 million due to the narrowing of the project's scope. The original project envisioned the design and replacement of 48 relays. Approximately 25% of the relays have been replaced to date and the replacement of the remaining relays has been postponed. As a result of changing priorities and budget constraints, relays will be replaced on an as needed basis.

Behchoko Modular Two Megawatt Diesel Generator

2014/15 Capital Addition: $2,741,000 Total Budget: $2,742,000

This project consisted of purchasing a larger used 2MW diesel generator that was mounted in a modular building in Behchoko. In addition, the Corporation purchased and modified a used modular building (40 foot shipping container with special enclosures) to house a new switchgear and control panel, and built a concrete retaining pad for the transformer. The purpose of this project was to resolve short term capacity and reliability issues in the Behchoko power plant. The total project spend of $2.741 million was slightly below the original total budget of $2.742 million.

Norman Wells Plant Heating Conversion

2014/15 Capital Addition: $392,000 Total Budget: $410,000

This is year one of two of a multi-year project. This project involves the installation of a new NTPC standard 90,000L storage tank in Norman Wells. This plant's existing 4,000L backup diesel storage tank does not have the required capacity for extended operating periods. The installation of new larger tank will allow NTPC to meet the power needs of the community for extended periods when Imperial Oil shuts down its plant for repairs and maintenance. The total project spend of $0.570 million was above the original total budget of $0.410 million.

Taltson Zone:

Fort Smith Distribution System Upgrade

2014/15 Capital Addition: $1,412,000 Total Budget: $1,607,000

This project consisted of completing system reinforcement work on the Fort Smith Distribution line. The distribution system was converted from 2.4 / 4.16 kV to 14.4 / 24.9 kV, and the McDougal Street three-phase distribution line was rebuilt from a single circuit to a double circuit feeder. This system reinforcement work provided the Fort Smith distribution system with sufficient capacity to serve the town's load for the foreseeable future, based on a zero percent load growth rate. This work also permits the system to accommodate the addition of Interruptible Electric Heat Load up to a maximum of 2.0 megawatts. This project was carried forward from the 2012/14 GRA (Distribution System Upgrade). The total project spend of $1.412 million was below the original total budget of $1.607 million.

Fort Smith Bucket Truck Storage Facility

2014/15 Capital Addition: $313,000 Total Budget: $623,000

This is year two of two of a multi-year project that began in 2013/14. This project entailed constructing a fabric structure for the storage of a new bucket truck for the Transmission and Distribution Division in Fort Smith, as the existing facilities at Fort Smith were not large enough for storage of the new bucket truck. The Corporation purchased a land lot in Fort Smith adjacent to the existing plant and cleared the site in preparation for construction and site access. The storage of the truck reduces the truck's exposure to the elements while not in use and maximizes its useful life. The total project spend of $0.688 million was above the original total budget of $0.623 million.

Thermal Zone:

Jean Marie River Engine Replacement

2014/15 Capital Addition: $756,000 Total Budget: $540,000

This project was carried out to replace a Detroit D4-71 diesel generator (G1) at the Jean Marie River power plant and replace it with a new 106 kW air cooled Deutz generator. The community of Jean Marie River has constructed a water treatment plant and requires additional generation capacity. This new unit provides the required capacity, improves fuel efficiency and reduces noise levels at the plant. The total project spend of $0.756 million was above the original total budget of $0.540 million. This project was over budget due to unforeseen issues with the engine replacement and revised project

scope. This project was carried forward from the 2012/14 GRA (Replace Engine DD 4-71).

Jean Marie River Three Phase Automation & Breaker Upgrade

2014/15 Capital Addition: $928,000 Total Budget: $972,000

This project was undertaken to convert the Jean Marie River plant from single-phase to three-phase and to complete automation at the plant. The project consists of installing two new feeders, switchgear cabinets, breaker contactors, and feeder protection in the plant. Completion of the project increased the plant's reliability, allowing it to continue to meet power requirements during peak loads. In addition, the project improved operational performance from automation and reduced power restoration time after an outage. The total project spend of $0.928 million was slightly below the original total budget of $0.972 million. This project was presented as two separate projects in the 2012/14 GRA. The first project ($0.486 million budget) was to convert the interior of the Jean Marie River plant (installing new switch gear, feeders and breakers). The second project ($0.486 million budget) was to upgrade the single phase distribution to three-phase distribution.

Gameti Engine Replacement & Plant Heat Recovery

2014/15 Capital Addition: $1,277,000 Total Budget: $900,000

This project entailed replacing the CAT 3306 diesel generator with a more efficient unit and upgrading the heat exchanger on the G1 – CAT C10 generator at the Gameti power plant. This project was necessary to meet the PUB required firm capacity requirements and to ensure the power plant was able to continue to meet the power demands of the

community. The total project spend of $1.277 million was above the original total budget of $0.900 million, as the project was initially under scoped. The used generator was a containerized unit and required additional work to complete the installation. This expanded project scope required more onsite visits be completed by staff and contractors.

Inuvik Road Widening

2014/15 Capital Addition: $ 539,000 Total Budget: $546,000

This project consisted of widening a narrow road located behind the Corporation's warehouse in Inuvik. The project also required installation of a 60 meter retaining wall due to the grade from the road to the adjacent lots. The road behind the warehouse was extremely narrow making it difficult to deliver supplies to the warehouse and posing a safety hazard for personnel. The project corrected the access and safety issues. The total project spend of $0.539 million was slightly below the original total budget of $0.546 million.

Fort Good Hope Engine Replacement

2014/15 Capital Addition: $914,000 Total Budget: $950,000

This is year one of two of a multi-year project. This project involved replacing the CAT 353 (G2) diesel generator in Fort Good Hope. It also included upgrading the heat exchanger on the CAT 3508 G3 generator and raising the fuel day tank. The G2 generator was replaced with a new 350 kW genset that met the power requirements of the community while ensuring the required firm capacity requirement of 110% was met. The old unit was inefficient and reduced the plant's overall level of efficiency. The total

project spend of $1.268 million was above the original total budget of $0.950 million. This project was over budget as further engineering design was required to install the aftercooler, which was discovered during testing and commissioning. The engine aftercooler needed to be relocated closer to the engine and resulted in a change to the structural design.

Colville Lake Modular Power Plant

2014/15 Capital Addition: $468,000 Total Budget: $6,606,000

This is year one of two of a multi-year project. This project entailed the procurement of a new modular diesel power plant with the addition of a battery bank and solar panels at Colville Lake. The diesel plant operates as the primary supply to the community, while solar panels provide supplemental renewable generation. With the support of the battery bank, the solar generation offsets diesel generation, including periods when the diesel engines are not required to be operated. A major project permit application for this project was approved by the PUB on March 10, 2015 as per Decision 7-2015. The total project spend of $7.368 million exceeds the original total budget of $6.606 million. The original budget amount reflects the net cost of the project which includes government funding. The capital addition shown above is the amount added to gross plant in service. The government funding portion has been applied in customer contributions (Schedule 11.3). The net assets in service (Schedule 11.0) reflect the capital addition less the government funding.

Inuvik Plant Reliability Improvement

2014/15 Capital Addition: $654,000 Total Budget: $197,000

This project was undertaken to address a number of deficiencies that negatively affect the reliability and safety at the Inuvik EMD power plant. The EMD plant is used in a stand-by capacity and as such, it has not received the level of investment as the K-Plant. In 2012 two outages occurred, which the Corporation investigated and consequently identified a number of deficiencies at the plant. These include: Numerous plant systems were a single point of failure (e.g. radiator control), critical systems lacked redundancy (deadbus relays), manual operation of plant not possible (no local mode on generators), and equipment protection systems (e.g. circuit breakers) were lacking. This project addressed these issues by correcting the deficiencies identified, and allowed the Corporation to prevent customer outages and the associated costs of plant failure. The total project spend of $0.654 million was above the original total budget of $0.197 million. As the Corporation planned the project and determined the extent of the deficiencies, the project grew in scope and complexity.

11.2.2 Forecast Capital Projects for 2015/16 Over $400,000

The following is a summary description of the capital additions for all projects with a capital budget over $400,000 for 2015/16.

Snare Zone:

Snare Cascades – Spillway Repairs

2015/16 Capital Addition: $414,000 Total Budget: $700,000

This project consists of repairing the labyrinth spillway located at the Snare Cascades hydroelectric plant. Over the years, the labyrinth spillway has been significantly

damaged due to water erosion putting the safety of the dam at risk. The concrete will be repaired to ensure the continued safe operation of the dam. The total project spend of $0.414 million was below the original total budget of $0.700 million. The project was awarded on a time plus materials basis, this contract method allowed NTPC to share the project execution risks with the contractor and eliminate the contingency premium associated with a fixed price contract. As a result, the project was completed significantly under budget.

North Slave Protective Relay Upgrades

2015/16 Capital Addition: $423,000 Total Budget: $3,499,000

This is year two of three of a multi-year project. This project was undertaken to replace obsolete electromechanical relays with new electronic relays for the North Slave system. It was expensive and more operationally challenging to maintain obsolete relays, which had the additional need for periodic calibration. The new relays require less maintenance and provide better system protection thereby increasing the reliability of the North Slave power system. The total project spend of $0.875 million was significantly below the original total budget of $3.499 million due to the narrowing of the project's scope. The original project envisioned the design and replacement of 48 relays. Approximately 25% of the relays have been replaced to date and the replacement of the remaining relays has been postponed. As a result of changing priorities and budget constraints, relays will be replaced on an as needed basis.

Spillway 5B Improvements

2015/16 Capital Addition: $339,000 Total Budget: $440,000

This project entails correcting the deficiencies identified in the 2011 Dam Safety Review (DSR) related to Spillway 5B that connects to the Snare River system. Freeze/thaw conditions caused damage to the secondary concrete structure with minor erosion evident. NTPC has undertaken spillway repairs to correct safety concerns and prevent stoplog removal issues. The total project spend of $0.339 million was below the original total budget of $0.440 million.

Jackfish T10 Refurbishment

2015/16 Capital Addition: $491,000 Total Budget: $447,000

This project involves the complete refurbishment of the T10 transformer at the Jackfish power plant. The T10 transformer located at a Jackfish substation was damaged in 2013 resulting in the CAT plant at Jackfish becoming effectively disconnected from the Yellowknife grid. The reconnection of the CAT plant to the Yellowknife grid is essential, as it will increase the available capacity from Jackfish and enable the plant to serve as an effective backup to meet Yellowknife power demand as needed. The total project spend of $0.491 million was above the original total budget of $0.447 million.

North Slave Two Megawatt Mobile Diesel Generator

2015/16 Capital Addition: $139,000 Total Budget: $1,600,000

This is year two of two of a multi-year project. This project consisted of purchasing a two megawatt mobile diesel generator for the Jackfish power plant in Yellowknife. The new generator provided an immediate increase to the available capacity of the Snare-Yellowknife system. The low water event on the Snare hydro system required the Jackfish facility to be run on a continuous basis and increased the probability of failure

of the existing generators. The mobile genset provides backup power generation in the event of a failure of the older generators. The total project spend of $1.505 million was slightly below the original total budget of $1.600 million.

Jackfish T3 Replacement

2015/16 Capital Addition: $1,220,000 Total Budget: $1,281,000

Replacement of the T3 transformer is required at the Jackfish power plant to increase the plant's capacity, add transformer redundancy, continue to meet RFC requirements and provide long term planning options. The new transformer will provide flexibility to install future modular units (in addition to the 5-6MW planned) or to connect battery renewable systems. The total project spend of $1.220 million was slightly below the original total budget of $1.281 million.

Thermal Zone:

Inuvik Tank F Bulk Fuel Storage Upgrade

2015/16 Capital Addition: $660,000 Total Budget: $3,511,000

This is the final year of a multi-year project that carried forward from the 2012/14 GRA. This project consisted of upgrading Tank F, associated infrastructure (piping, berm) and construction of a new truck loading station. These upgrades were necessary for the tank to remain compliant with regulatory requirements, current industry practice and a contractual obligation with the Fuel Service Division of the GNWT. The tank stores fuel for generation in Inuvik, Fort McPherson and Tsiigehtchic. The Corporation risked a structural failure if the tank, piping, and berm were left in their current state, which could result in a major diesel spill. In order to ensure the tank continues to operate in a safe

and reliable way, it was essential that the upgrades be completed. The total project spend of $4.453 million was above the original total budget of $3.511 million. The market for the associated work increased from the time the initial budget was prepared until NTPC went to obtain tenders, which resulted in higher than anticipated prices. In addition, there was a project design issue with the leak detection system. The original design did not perform as expected and additional work was required to ensure the safe operation of the tank.

Fort Good Hope Engine Replacement

2015/16 Capital Addition: $354,000 Total Budget: $950,000

This is year two of two of a multi-year project. This project involved replacing the CAT 353 (G2) diesel generator in Fort Good Hope. It also included upgrading the heat exchanger on the CAT 3508 G3 generator and raising the fuel day tank. The G2 generator was replaced with a new 350 kW genset that met the power requirements of the community while ensuring the required firm capacity requirement of 110% was met. The old unit was inefficient and reduced the plant's overall level of efficiency. The total project spend of $1.268 million was above the original total budget of $0.950 million. This project was over budget as further engineering design was required to install the aftercooler, which was discovered during testing and commissioning. The engine aftercooler needed to be relocated closer to the engine and resulted in a change to the structural design.

Norman Wells Plant Heating Conversion

2015/16 Capital Addition: $178,000 Total Budget: $410,000

This is year two of two of a multi-year project. This project involves the installation of a new NTPC standard 90,000L storage tank in Norman Wells. This plant's existing 4,000L backup diesel storage tank does not have the required capacity for extended operating periods. The installation of new larger tank will allow NTPC to meet the power needs of the community for extended periods when Imperial Oil shuts down its plant for repairs and maintenance. The total project spend of $0.570 million was above the original total budget of $0.410 million.

Inuvik 5kV Breaker Replacement

2015/16 Capital Addition: $367,000 Total Budget: $628,000

This is year three of five of a multi-year project. The project entails upgrading the generation and feeder 5kV breakers at the Inuvik power plant that have reached the end of their useful life. Replacement parts are becoming difficult to procure and new parts are no longer manufactured. The breakers are becoming more problematic to operate, thus putting the generation and feeder equipment at risk of failure and extended outage durations. The breakers are to be replaced on a five year rotational program to minimize the impact on the operations. The new vacuum breakers are expected to provide over 30 years of continuous service with readily available parts and problem free operation. The total project spend of $0.527 million was below the original total budget of $0.628 million.

Jean Marie River Fuel System Upgrade

2015/16 Capital Addition: $543,000 Total Budget: $477,000

This project consists of the installation and commissioning of a new fuel system and main fuel tank for the Jean Marie River plant. This project is part of a long standing corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. The Corporation monitors regulatory requirements and incorporates these requirements into the 5 year Capital Program. This program replaces/upgrades assets as required to ensure NTPC meets existing regulatory codes. In addition, the Capital Program is updated as regulatory changes occur, ensuring the Corporation continues to meet regulatory requirements. The upgrade of the fuel system at Jean Marie River will reduce the risk of fuel spills and the associated environmental concerns, as well as reduce plant downtime. The total project spend of $0.543 million was above the original total budget of $0.477 million.

Colville Lake Modular Power Plant

2015/16 Capital Addition: $6,900,000 Budget: $6,606,000

This is year two of two of a multi-year project. This project entailed the procurement of a new modular diesel power plant with the addition of a battery bank and solar panels at Colville Lake. The diesel plant operates as the primary supply to the community, while solar panels provide supplemental renewable generation. With the support of the battery bank, the solar generation offsets diesel generation, including periods when the diesel engines are not required to be operated. A major project permit application for this project was approved by the PUB on March 10, 2015 as per Decision 7-2015. The total project spend of $7.368 million exceeds the original total budget of $6.606 million. The original budget amount reflects the net cost of the project which includes

government funding. The capital addition shown above is the amount added to gross plant in service. The government funding portion has been applied in customer contributions (Schedule 11.3). The net assets in service (Schedule 11.0) reflect the capital addition less the government funding.

Corporate/Head Office:

Selection and Installation of a Lone Worker System

2015/16 Capital Addition: $665,000 Total Budget: $839,000

NTPC reviewed its current lone worker systems and determined those were deficient and needed to be upgraded. Following a structured model for systems deployment, NTPC will undertake the selection and installation of a standardized man down alarm system for use at all of NTPC's generation plants. This will enable the Corporation to maintain operational effectiveness, and improve worker safety, a key strategic initiative. The total project spend of $0.665 million was below the original total budget of $0.839 million.

Computerized Maintenance Management System (CMMS)

2015/16 Capital Addition: $3,371,000 Total Budget: $4,471,000

This is year one of three of a multi-year project. The project consists of implementing a CMMS that integrates with existing NTPC systems to enable end-to-end asset management and maintenance of asset life cycles. CMMS allows for asset tracking, planning, maintenance work order management, subcontractor management, recording unit downtime, recording historical maintenance events, maintenance analytics and full integration with existing financial systems. In the previous GRA, a Computerized

Maintenance System was listed as an expected capital project. The CMMS project is a related project with a substantially expanded scope including customization of the application, integration of CMMS with financial systems and training costs for staff. Given the substantial change in scope, a revised budget has been presented. The total estimated project cost is equal to the current budget of $4.471 million.

11.2.3 Actual Capital Projects for 2016/17 Over $400,000

The following is a summary description of the capital additions for all projects with a capital budget over $400,000 for 2016/17.

Snare Zone:

Jackfish Mirrlees Replacement

2016/17 Capital Addition: $6,483,000 Total Budget: $6,485,000

This project entails the purchase and installation of two mobile generator sets (4 - 5MW of total generation) to address the retirement of one Mirrlees diesel generator. This will allow the Corporation to meet its required firm capacity requirements for the Snare System, provide cost effective generation and greater flexibility/contingency generation. A major project permit application was approved for this project by the PUB on December 10th, 2015 as per Decision 15 – 2015.

Snare Cascades New Electronic Governor

2016/17 Capital Addition: $2,500,000 Total Budget: $2,500,000

This project consists of installing a new electronic governor at the Snare Cascades hydro plant. The Snare Hydro system has historically suffered many system instability

issues. This has resulted in a number of power outages that could have been prevented if an electronic governor was in place. The mechanical governors operating at the Snare Cascades hydro plant are old technology and due to be replaced. The installation of an electronic governor will improve overall system reliability.

Snare Transmission Lightning Protection

2016/17 Capital Addition: $1,155,000 Total Budget: $1,155,000

This project entails installing Class 3 lightning arrestors on the L199 transmission line that connects to Yellowknife. Transmission lines are generally protected from lightning by shield wires. Ice build-up along a 16.5 km section of the line caused the shield wire to sag, which resulted in the Corporation removing the shield wires from this section of L199. Lightning strikes to the unshielded section caused outages during the summer months. External consultants recommended installing lightening arrestors on the unshielded portion of the line to prevent outages from lightning strikes.

North Slave Protective Relay Upgrades

2016/17 Capital Addition: $36,000 Total Budget: $3,499,000

This is year three of three of a multi-year project. This project was undertaken to replace obsolete electromechanical relays with new electronic relays for the North Slave system. It was expensive and more operationally challenging to maintain obsolete relays, which had the additional need for periodic calibration. The new relays require less maintenance and provide better system protection thereby increasing the reliability of the North Slave power system. The total project spend of $0.875 million was significantly below the original total budget of $3.499 million due to the narrowing of the

project's scope. The original project envisioned the design and replacement of 48 relays. Approximately 25% of the relays have been replaced to date and the replacement of the remaining relays has been postponed. As a result of changing priorities and budget constraints, relays will be replaced on an as needed basis.

Snare Falls Mechanical Overhaul

2016/17 Capital Addition: $8,958,000 Total Budget: $10,443,000

This project involves the mechanical overhaul of the 7.4 MW generator and turbine assembly at unit 1 of the Snare Falls Hydro Generation facility. The Snare Falls unit has been operating at 53% of rated capacity since March 2015. A malfunction of the unit's lubricant system resulted in a release of lube oil in 2014. A major overhaul will address these and other operating issues at the plant. The overhaul of Snare Falls is expected to create efficiency gains, minimize the potential for future lube or grease spills into watersheds, and provide reliable generation. A major project permit application for this project was approved by the PUB on December 10th, 2015 as per Decision 16-2015. The total estimated project spend of $8.958 million is below the original total budget of $10.443 million, as this estimate excludes fuel related costs.

Taltson Zone:

Fort Resolution Rebuild Distribution Feeder

2016/17 Capital Addition: $598,000 Total Budget: $598,000

This project involves rebuilding a 3.2 km section of the distribution line that begins at the Pine Point substation. The current distribution line is difficult to access given the area and nature of the terrain. The poles and cross arms are at the end of their useful life and

require replacement. As part of the project, the distribution line will be relocated closer to an existing roadway from the present line location. This project will prevent structural failure, improve power line reliability, and is expected to reduce the cost of replacing poles and servicing the line.

Fort Smith Load Bank

2016/17 Capital Addition: $719,000 Total Budget: $719,000

This project consists of installing a load bank at the Pine Point substation for the Taltson Hydro unit. During the winter season, when the load on the Taltson system is between 12.3 - 13.0 MW, there is a resonant vibration that occurs, known as the rough zone. The vibration is quite significant when the system enters this zone of operation and is a dam safety concern. The load bank would add load to the Taltson system when the existing load is in the rough zone range. This would prevent Taltson from operating in the rough zone eliminating this dam safety risk and removing the potentially significant negative outcomes such as plant damage and reduced useful life.

Fort Smith IMH Metering Upgrade

2016/17 Capital Addition: $653,000 Total Budget: $653,000

This project entails replacing the current automatic meter reading system in Fort Smith with a new 2-way metering system. The current automatic meter reading system in Fort Smith is starting to fail and requires replacement. The Corporation has identified a new 2-way metering system to replace the existing meters. This new metering system will provide an improved customer experience and provide benefits to day-to-day corporate

operations. This project is a part of the IMH Metering Upgrade major project permit that was submitted with this GRA.

Thermal Zone:

Ulukhatok Main Fuel Storage Tank

2016/2017 Capital Addition: $552,000 Total Budget: $552,000

This project involves the purchase and installation of a new main tank for the Ulukhaktok power plant. The current tank is past its useful life and needs to be replaced. This project is part of a long outstanding corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. In order to ensure the tank is safe and reliable, the tank must be replaced to prevent a major diesel spill from occurring.

Aklavik Variable Speed Generator

2016/17 Capital Addition: $1,449,000 Total Budget: $1,449,000

This project entails the installation of a variable speed generator in the Aklavik power plant. The 600 kW variable speed unit has been successfully used in other markets and has fuel efficiency of 3.9kWh/L. This is a pilot project to evaluate how such a unit will perform in the unique challenging environment of the Corporation. Variable speed generation has the potential to minimize cost and provide the most fuel efficient solution to thermal communities.

Inuvik 5kV Breaker Replacement

2016/17 Capital Addition: $80,000 Total Budget: $628,000

This is year four of five of a multi-year project. The project entails upgrading the generation and feeder 5kV breakers at the Inuvik power plant that have reached the end of their useful life. Replacement parts are becoming difficult to procure and new parts are no longer manufactured. The breakers are becoming more problematic to operate, thus putting the generation and feeder equipment at risk of failure and extended outage durations. The breakers are to be replaced on a five year rotational program to minimize the impact on the operations. The new vacuum breakers are expected to provide over 30 years of continuous service with readily available parts and problem free operation. The total project spend of $0.527 million was below the original total budget of $0.628 million.

Corporate/Head Office:

Computerized Maintenance Management System (CMMS)

2016/17 Capital Addition: $715,000 Total Budget: $4,471,000

This is year two of three of a multi-year project. The project consists of implementing a CMMS that integrates with existing NTPC systems to enable end-to-end asset management and maintenance of asset life cycles. CMMS allows for asset tracking, planning, maintenance work order management, subcontractor management, recording unit downtime, recording historical maintenance events, maintenance analytics and full integration with existing financial systems. In the previous GRA, a Computerized Maintenance System was listed as an expected capital project. The CMMS project is a related project with a substantially expanded scope including customization of the

application, integration of CMMS with financial systems and training costs for staff. Given the substantial change in scope, a revised budget has been presented. The total estimated project cost is equal to the current budget of $4.471 million.

11.2.4 Forecast Capital Projects for 2017/18 Over $400,000

The following is a summary description of the capital additions for all projects with a capital budget over $400,000 for 2017/18.

Snare Zone:

Jackfish Control Systems Upgrade

2017/2018 Capital Addition: $880,000 Total Budget: $880,000

This project entails updating the settings on the current control system equipment and designing replacement equipment at the Jackfish power plant in Yellowknife. This plant has a number of control system problems when an outage occurs, resulting in delays to switch over to the backup system (Jackfish). This project seeks to achieve the best possible performance from the existing control systems and to design a replacement system to provide a permanent solution.

Jackfish T4 Transformer Upgrade

2017/18 Capital Addition: $656,000 Total Budget: $656,000

This project involves completing a refurbishment of the T4 transformer at the Jackfish substation in Yellowknife. This project would entail refurbishing the T4 unit and using it as a standby transformer for the newer T19 transformer. A transformer failure at Jackfish could cause a long-term outage while a replacement is sought. The completion

of this refurbishment project would provide NTPC with access to a backup transformer if the T19 transformer failed.

Snare Rapids Excitation System Upgrade

2017/18 Capital Addition: $604,000 Total Budget: $604,000

This project consists of replacing the current excitation system at the Snare Rapids plant. An excitation system is a key piece of equipment used to control the voltage of a power system and to provide stability to the system. The current excitation system at Snare Rapids has passed its designed life expectancy and is experiencing various technical problems. The installation of a new system will allow the Corporation to reduce the risk of unplanned outages at the Snare Rapids plant.

Jackfish Supervisory Control and Data Acquisition (SCADA) System Replacement

2017/18 Capital Addition: $1,516,000 Total Budget: $1,906,000

This is year one of two of a multi-year project. This project involves replacing the SCADA servers and host software system at the Jackfish power plant in Yellowknife. By using the latest SCADA software the Corporation will realize numerous operational benefits including improved efficiency, energy and data management, along with annual cost savings. This would better align the production system with the corporate systems, and bring NTPC's system into alignment with industry standards and best practices. The total estimated project cost is equal to the current budget of $1.906 million.

Thermal Zone:

Inuvik K-Plant Combustion Air Upgrade

2017/18 Capital Addition: $784,000 Total Budget: $784,000

This project entails upgrading the ventilation system in the Inuvik K-Plant. The current ventilation system was designed to accommodate two natural gas generators. However, while a third generator was added in 2005 the plant ventilation was not upgraded to accommodate this plant modification resulting in a number of issues. The upgrade of the ventilation system will allow the generators to operate at peak output and efficiency which is expected to reduce fuel costs, improve plant reliability, lower maintenance costs and reduce exhaust emissions.

Inuvik New Exhaust Gas Recover Unit

2017/18 Capital Addition: $1,773,000 Total Budget: $1,773,000

This project at the Inuvik K-Plant consists of completing upgrades to the G10 natural gas generator and the installation of an Exhaust Gas Recovery Unit (EGRU) on the heat recovery system of G10. These modifications will increase the available residual heating supply. The Inuvik heat distribution systems are experiencing a high level of demand from NTPC facilities and municipal facilities in the community. The present use of backup boilers to provide heat is very inefficient. The upgrades to the generator and addition of an EGRU will provide a more efficient heating system with potential increases in plant efficiency and reduced operating costs.

Inuvik 5kV Breaker Replacement

2017/18 Capital Addition: $80,000 Total Budget: $628,000

This is year five of five of a multi-year project. The project entails upgrading the generation and feeder 5kV breakers at the Inuvik power plant that have reached the end of their useful life. Replacement parts are becoming difficult to procure and new parts are no longer manufactured. The breakers are becoming more problematic to operate, thus putting the generation and feeder equipment at risk of failure and extended outage durations. The breakers are to be replaced on a five year rotational program to minimize the impact on the operations. The new vacuum breakers are expected to provide over 30 years of continuous service with readily available parts and problem free operation. The total project spend of $0.527 million was below the original total budget of $0.628 million.

Inuvik New Station PLC

2017/18 Capital Addition: $495,000 Total Budget: $495,000

This project consists of replacing the current station PLCs in the Inuvik K-plant and EMD plant. Inuvik was one of the first communities to undergo automation in the early 1990's. The existing station PLCs that run the plants are at the end of their useful lives and starting to fail. Outages caused by these failures can be extensive and two incidents have already occurred. In order to reduce the likelihood of outages, replacement of the PLC hardware and software is required for the Inuvik plant.

Nahanni Butte Fuel System Upgrade

2017/18 Capital Additions: $905,000 Total Budget: $905,000

This project consists of the installation and commissioning of a new fuel system and main fuel tank for the Nahanni Butte plant. This project is part of a long outstanding

corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. The upgrade of the fuel system and main tank will reduce the risk of fuel spills and the associated environmental concerns, as well as reduce plant downtime.

Paulatuk New Living Accommodations

2017/18 Capital Addition: $419,000 Total Budget: $419,000

This project involves the acquisition and installation of a trailer in Paulatuk to provide appropriate temporary accommodations for staff who service the local plant. The current temporary accommodation is a local hotel. The hotel is a shared accommodation, which pose health, safety, and privacy concerns for staff. The hotel also has limited space and is not always available in short notice situations.

Tulita Day Fuel Tank

2017/18 Capital Addition: $570,000 Total Budget: $570,000

This project consists of upgrading the fuel day tank and fuel transfer system at the Tulita power plant. This project is part of a long outstanding corporate initiative to upgrade the fuel tanks, piping, and related systems at diesel based plants. These upgrades will enhance plant safety, reliability and ensure compliance with current regulatory requirements. The fuel transfer system at the plant provides insufficient fuel for the diesel engines to run effectively. Upgrading the day tank and fuel transfer system, will allow for the safe transfer of fuel from the main storage tank to the day tank. In addition,

fuel will be supplied to the diesel engines in sufficient quantities to allow them to run more efficiently.

Corporate/Head Office:

Computerized Maintenance Management System (CMMS)

2017/18 Capital Addition: $385,000 Total Budget: $4,471,000

This is year three of three of a multi-year project. The project consists of implementing a CMMS that integrates with existing NTPC systems to enable end-to-end asset management and maintenance of asset life cycles. CMMS allows for asset tracking, planning, maintenance work order management, subcontractor management, recording unit downtime, recording historical maintenance events, maintenance analytics and full integration with existing financial systems. In the previous GRA, a Computerized Maintenance System was listed as an expected capital project. The CMMS project is a related project with a substantially expanded scope including customization of the application, integration of CMMS with financial systems and training costs for staff. Given the substantial change in scope, a revised budget has been presented. The total estimated project cost is equal to the current budget of $4.471 million.

Roof Replacement Head Office

2017/18 Capital Addition: $500,000 Total Budget: $500,000

This project consists of installing a new roof at the Corporation's head office location in Hay River. The current roof is nearing the end of its useful life and inspections have revealed deterioration of the waterproof membrane. Failure to replace the current roof will result in water leaks and pose health and safety risks to staff. The new roof will

prevent water from leaking into the building and the potential structural damage and mold proliferation which could occur.

IMH Metering Upgrade

2017/18 Capital Addition: $1,000,000 Total Budget: $4,247,000

This is year one of four of a multi-year project. This project involves installing a 2-way metering systems in all of the communities the Corporation serves except Fort Smith (separate project) and Jean Marie River (pilot project). The current automatic meter reading system in the larger communities is starting to fail and requires replacement. The smaller communities currently use standard meters. This new metering system will provide an improved customer experience and provide benefits to day-to-day corporate operations. This project is a part of the IMH Metering Upgrade major project permit that was submitted with this GRA. The total estimated project cost is equal to the current budget of $4.247 million.

11.2.5 Forecast Capital Projects for 2018/19 Over $400,000

The following is a summary description of the capital additions for all projects with a capital budget over $400,000 for 2018/19.

Snare Zone:

Spillway 5B Distribution Line

2018/19 Capital Addition: $1,229,000 Total Budget: $1,229,000

This project entails replacing the distribution line to Spillway 5B at the Snare Rapids plant. The current distribution line is nearly 60 years old and past its useful life. A

spillway is a structure used to provide the controlled release of flows from a dam. The spillway requires a continuous reliable power source for the crane to move stop logs and for the heaters used to prevent the logs from freezing in the winter. A new distribution line will ensure Spillway 5B has a reliable power source and can continue its critical function.

Snare Forks Hydro Unit Overhaul

2018/19 Capital Addition: $7,862,000 Total Budget: $7,862,000

This project consists of completing an overhaul on Snare Forks hydroelectric Unit 1. An inspection completed in 2014 identified a number of major and minor deficiencies. Without correction, the condition of the unit will continue to degrade and a more serious failure could occur. The completion of the overhaul would help to prevent unplanned outages, maintain the reliability of the Snare hydro system, and reduce deterioration of the asset and its associated capital costs. A major project permit for this project was submitted with this GRA.

Jackfish Supervisory Control and Data Acquisition (SCADA) System Replacement

2018/19 Capital Addition: $390,000 Total Budget: $1,906,000

This is year two of two of a multi-year project. This project involves replacing the SCADA servers and host software system at the Jackfish power plant in Yellowknife. By using the latest SCADA software the Corporation will realize numerous operational benefits including improved efficiency, energy and data management, along with annual cost savings. This would better align the production system with the corporate systems,

and bring NTPC's system into alignment with industry standards and best practices. The total estimated project cost is equal to the current budget of $1.906 million.

Jackfish T5 Transformer Replacement

2018/19 Capital Addition: $789,000 Total Budget: $789,000

This project entails replacing the T5 transformer at the Jackfish power plant in Yellowknife. The T5 transformer was installed in 1958 and has reached the end of its useful life. If the transformer fails, plant operators will not be able to connect Snare hydro generation to the distribution system to supply Yellowknife with electricity. As a result, diesel generation will have to be used. Replacing the T5 transformer with a new unit will allow NTPC to continue to provide Yellowknife customers with reliable low cost hydroelectric power.

Jackfish K-Plant Cooling System Upgrade

2018/19 Capital Addition: $791,500 Total Budget: $791,500

The project consists of replacing all of the water cooling piping in the Jackfish K-Plant in Yellowknife. The water cooling pipes are corroded and approaching the end of their useful life. The piping issues limit the ability of the cooling system to properly cool the diesel generators (gensets), forcing the plant operators to de-rate the gensets and operate the units below their peak output. Upgrading the cooling system will allow the gensets to operate at peak output, which will increase total plant diesel generation output capacity and improve overall plant reliability. The cooling system upgrade will also provide better cooling to the gensets and prevent overheating which is expected to improve engine reliability and reduce maintenance costs over time.

Thermal Zone:

Nahanni Butte Engine Replacement

2018/19 Capital Addition: $632,000 Total Budget: $632,000

This project involves replacing the G2 Detroit D4-71 diesel generator at the Nahanni Butte plant. The G2 unit is undersized to meet the community's needs and has a low fuel efficiency of only 2.5kWh/L. Given the load requirements of the community and following the RFC requirements as laid out by the PUB, Nahanni Butte will require a 120 kW unit. Installing a new 120 kW unit will provide the required capacity, improve backup efficiency, reduce exhaust and noise emissions and enhance reliability of the plant.

Norman Wells Plant Replacement

2018/19 Capital Addition: $4,600,000 Total Budget: $4,600,000

This project consists of replacing the current power plant in Norman Wells with a new modular plant. The current plant in Norman Wells has major structural problems. The building foundation is collapsing posing safety risks to the equipment inside the plant and the staff who operate it. There is also a risk of a fuel spill or coolant leak putting the environment at risk. A new plant is required to provide reliable power supply and safeguard the environment. A major project permit for this project was submitted with this GRA.

Inuvik Paint Tank F

2018/19 Capital Addition: $585,000 Total Budget: $585,000

This project entails repainting Tank F at the Inuvik tank farm. The paint on Tank F is fading and there are signs of pitting and rust. The tank stores fuel for generation in Inuvik, Fort McPherson and Tsiigehtchic. The Corporation risks a structural failure if the tank is left in its current state which would result in a major diesel spill and put the environment, staff and the entire Inuvik tank farm at risk. In order to ensure the tank continues to operate in a safe and reliable way, it is essential that the tank is repainted.

Jean Marie River G3 Engine Replacement

2018/19 Capital Addition: $625,000 Total Budget: $625,000

This project involves replacing the G3 Detroit D4-71 diesel generator at the Jean Marie River plant. The G3 unit is undersized to meet the community's needs and is only run when necessary. The G1 and G2 units generate over 95% of the plants power. Continued operation in this manner will shorten engine life and increase maintenance costs on these generators and reduce engine reliability. Installing a new generator will increase plant capacity, enhance reliability and improve load sharing across all units reducing maintenance.

Corporate/Head Office:

IMH Metering Upgrade

2018/19 Capital Addition: $1,000,000 Total Budget: $4,247,000

This is year two of four of a multi-year project. This project involves installing a 2-way metering systems in all of the communities the Corporation serves except Fort Smith, which is a separate project. The current automatic meter reading system in the larger communities is starting to fail and requires replacement. The smaller communities

currently use standard meters. This new metering system will provide an improved customer experience and provide benefits to day-to-day corporate operations. This project is a part of the IMH Metering Upgrade major project permit that was submitted with this GRA. The total estimated project cost is equal to the current budget of $4.247.

11.3 NECESSARY WORKING CAPITAL

The working capital requirement submitted in this Application is the estimated cash the Corporation will be required to have on-hand to meet day to day operating needs. There are two components to working capital, inventory and cash working capital. Inventory includes items critical for day to day operation including fuel, lube, and supplies. Cash working capital is the cash the corporation requires to have on-hand to cover operational cash-based expenses (specifically those not covered by other sections of this application e.g. Deferrals). Please refer to section 14.2.1 for a description of how the cash working capital requirement was calculated from the lead lag study. Schedules 5.7, 5.8, 5.9, 5.10 contain the cash working capital requirement by year. Schedule 5.6 outlines the calculation of the Corporation's total working capital requirement by year.

11.4 DEFERRAL ACCOUNTS AND DEFERRED EXPENSES

Regulatory Deferral Account

The regulatory deferral account includes costs for all regulatory hearings, regulatory processes and the costs for developing the Net Metering program which was directed

by the PUB. Details of the additions to the account are in Schedule 11.4 and the amortization provision is calculated to retire these costs over a five year period.

The 2013/14 Test Year amortization provision was $0.243 million and the Corporation is forecasting this increase to $0.512 million per year. The increase is from increased additional costs related to the 2012/14 GRA phase 1 and 2 Applications, the Minimum Filing Requirements project and increased costs to develop the Net Metering program.

Overhaul Deferral Account

The overhaul deferral account includes costs related to engine overhauls for thermal and hydro plants. Details of the additions to the account are in Schedule 11.4. The amortization provision approved by the PUB in the 2012/14 GRA included a “catch up” provision and a “keep up” provision. In the 2012/14 GRA the Board approved a 10 year catch up period to collect the 2012 overhaul balances. For this Application the catch up period was reduced from 10 years to 5 years in the Thermal and Snare zones to account for the 5 years that has passed since 2012 and to account for a small nominal balance in the Snare zone. The Corporation is proposing to maintain the 10 year collection period in the Taltson zone due to the standby nature of the diesel power plants in Fort Smith and Fort Resolution. The keep up portion is the average cost of overhauls over a 5 year period adjusted for known changes such as increased hydro overhaul costs for the Taltson plant. The 2013/14 Test Year amortization provision was $2.936 million and the Corporation is forecasting this to increase to $3.935 million in the current Application. The increase results from changing the catch up portion amortization provision from 10 years to 5 years for the Thermal and Snare zones and from increased annual overhaul costs in the Taltson zone. Costs associated with the

annual shutdown of the Taltson hydro plant have increased due to inflation and an increased scope of work related to the age of the equipment. In addition, the larger diesel engines in Fort Smith have scheduled major overhauls in 2016 and 2017.

Water License Deferral Account

The water deferral account includes costs related to licensing activities. Details of the additions to the account are in Schedule 11.4 and the amortization provision uses a "catch up" and "keep up" portion as approved by the PUB in the 2012/14 GRA. The catch up portion was calculated by collecting the 2015/16 year-end balance over the remaining life of the water license for each dam and the keep up portion is calculated by forecasting costs for water monitoring, dam inspections, environmental monitoring, dam brushing, dam crest surveys, dam safety reviews and dam license renewal costs. The 2014 Test Year amortization provision was $0.825 million and the Corporation is forecasting this to increase to $1.611 million. The annual keep up portion in the 2013/14 Test Year was forecast at $0.468 million and this is forecast to increase to $0.960 million. The lagging keep up portion also results in the catch up portion increasing from $0.358 million to $0.651 million. The increased annual costs relate to increased required environmental monitoring at Bluefish dam and Taltson dam, increased costs related to dam inspections as a result of dam safety reviews, required flood surveys and increased costs relating to annual dam testing and inspections.

Reserve For Injuries and Damages

The reserve for injuries and damages deferral account includes costs related to uninsured or uninsurable losses and the deductible portion of insured claims. Details of

the additions to the account are in Schedule 11.4 and the amortization provision is based on historical additions to the account. The 2013/14 Test Year amortization provision was $0.670 million and the Corporation is forecasting this to decrease to $0.250 million.

Employee Future Benefits

Under the terms and conditions of employment, employees may earn non-pensionable benefits for resignation, retirement and ultimate removal costs based on employee start dates, years of service, final salary and point of hire. The employee future benefits deferral account includes costs for the liability for employee future benefits. Details of the additions to the account are in Schedule 11.4 and the amortization provision uses a "catch up" and a "keep up" portion as approved by the Board in the 2012/14 GRA. The catch up portion was calculated by collecting the 2015/16 year-end balance over 10 years and the keep up portion is based on expected future annual costs.

Previous to 2014/15 the cost of the benefit reflected management's best estimates using expected compensation levels and years of service. In 2014/15 the Corporation prepared an actuarial valuation for accounting purposes of the employee future benefit plan using the projected benefits method. The actuarial valuation increased the balance by approximately $0.500 million in 2014/15. From 2013/14 to 2015/16 the average addition to the fund was approximately $0.500 million and based on the current workforce complement the Corporation is forecasting this amount to continue.

Deferral Expenses

Deferral expenses include costs for studies and programs that result in an intangible asset that has a benefit for more than one year. Studies and programs included as deferred expenses are the Enterprise Resource Planning ("ERP") project approved by the PUB in the 2012/14 GRA, International Financial Reporting Standards ("IFRS") conversion project approved by the PUB in the 2012/14 GRA, costs related to the Public Sector Accounting Standards ("PSAS") conversion project and the Power System Plan project. The amortization provision for the ERP, IFRS and PSAS projects is 10 years and the amortization provision for the Power System Plan is 5 years. The Corporation is also including IDC on inventory to be recovered in this account over a 20 year period. Interest on inventory is not permitted under PSAS and in order to have only one set of accounting records the Corporation is proposing to recover the interest through the deferral account and not working capital. Please refer to Section 1.6 for further information on the accounting changes. The 2013/14 Test Year amortization provision was $0.133 million and the Corporation is forecasting this to increase to $0.369 million by 2018/19. The increase is due to higher costs related to the ERP project than forecast, the required transition to PSAS accounting and the development of the Power System Plan.

The amortization provision for feasibility studies in the 2013/14 Test Year was $0.193 million and is forecast to increase to $0.332 million by 2018/19. The increase is driven by a $0.543 million Arc Flash Study and a $1 million asset condition assessment study. The purpose of the Arc Flash Study was to estimate the potential arc flash risk from the various pieces of equipment at NTPC. With results from the study, the Personal Protective Equipment standards were updated to protect workers from burn injuries.

The Arc Flash Study was forecast in the 2012/14 GRA but not completed until the 2014/15 fiscal year. The asset condition assessment study completed a comprehensive condition assessment of all generation, transmission and distribution assets at NTPC. The results of the study determined the age, life cycle and maintenance intervals of all assets from small pumps to large generating assets. The study was used in conjunction with the CMMS system and the Power System Plan to redevelop preventative maintenance programs and capital planning. In accordance with NTPC's accounting treatment, studies are amortized over a 5 year period. The amortization provision in the 2013/14 Test Year was included in plant amortization expense and as part of the Minimum Filing Requirements this is now in deferred expenses.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
RATE BASE
(in thousands of dollars)

Line No.		2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	Test Year 2017/18 Forecast	Test Year 2018/19 Forecast
1	**Gross Plant in Service**							
2	Beginning of Year	447,165	418,145	443,558	463,099	485,730	518,174	536,242
3	Add: Additions	17,899	28,041	23,439	24,568	35,287	19,605	24,726
4	Less: Disposals and Transfers	3,948	2,627	3,898	1,937	2,843	1,537	1,925
5	End of Year	461,116	443,558	463,099	485,730	518,174	536,242	559,043
6	Mid-Year Balance =(L2+L5)/2	454,141	430,851	453,328	474,414	501,952	527,208	547,643
7	**Accumulated Amortization**							
8	Beginning of Year	162,211	156,315	166,878	177,088	189,915	203,157	218,732
9	Add: Amortization Expense and True-Up	14,958	14,368	15,093	15,764	17,085	18,112	18,970
10	Less: Disposals, Transfers and other Adjustments	3,948	2,665	3,891	1,937	2,843	1,537	1,925
11	Less: Site Restoration Expenses	725	1,140	992	1,000	1,000	1,000	1,000
12	End of Year	172,495	166,878	177,088	189,915	203,157	218,732	234,776
13	Mid-Year Balance = (L8+L12)/2	167,353	161,596	171,983	183,501	196,536	210,944	226,754
14	**Mid-Year Net Plant in Service (L6 - L13)**	286,788	269,255	281,346	290,913	305,416	316,264	320,888
15	**Add: Mid-Year Deferral Accounts**	13,534	15,428	15,588	16,348	16,992	15,768	12,743
15	**Add: Mid-Year Deferred Expenses**	1,396	3,236	3,473	3,940	3,606	3,020	2,407
16	**Add: Mid-Year Working Capital**	2,786	3,265	3,542	3,174	3,369	3,493	3,513
17	**Less: Mid-Year Customer Contributions**	6,657	9,245	9,675	10,492	10,629	9,952	9,275
18	**Mid-Year Rate Base**	**297,847**	**281,940**	**294,274**	**303,883**	**318,753**	**328,593**	**330,276**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
GROSS PLANT IN SERVICE
(in thousands of dollars)

Line No.	Gross Plant by Major FERC Category	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
1	**Hydro Plant**							
2	Beginning of Year	165,200	160,104	162,975	166,877	168,232	181,591	183,457
3	Add: Additions	5,730	3,345	3,990	1,391	13,515	1,910	9,036
4	Less: Disposals and Transfers	3,948	475	88	36	156	43	89
5	End of Year	166,981	162,975	166,877	168,232	181,591	183,457	192,404
6	**Thermal Plant**							
7	Beginning of Year	157,124	141,035	159,193	168,175	177,863	188,594	198,499
8	Add: Additions	4,764	19,631	11,311	10,789	12,267	10,740	9,273
9	Less: Disposals and Transfers	-	1,473	2,329	1,101	1,536	835	1,061
10	End of Year	161,888	159,193	168,175	177,863	188,594	198,499	206,711
11	**Transmission Plant**							
12	Beginning of Year	49,694	49,569	49,606	50,899	53,661	55,655	56,736
13	Add: Additions	440	238	1,309	2,789	2,069	1,106	2,383
14	Less: Disposals and Transfers	-	201	17	27	74	26	41
15	End of Year	50,134	49,606	50,899	53,661	55,655	56,736	59,078
16	**Distribution Plant**							
17	Beginning of Year	31,189	30,673	32,162	35,078	36,687	38,354	40,427
18	Add: Additions	2,811	1,572	3,108	1,913	1,840	2,242	1,775
19	Less: Disposals and Transfers	-	82	191	304	173	168	158
20	End of Year	34,001	32,162	35,078	36,687	38,354	40,427	42,044
21	**General Plant**							
22	Beginning of Year	51,174	43,460	46,319	47,646	52,763	55,734	58,877
23	Add: Additions	4,154	3,255	2,599	5,585	3,874	3,608	2,259
24	Less: Disposals and Transfers	-	396	1,271	468	903	465	576
25	End of Year	55,328	46,319	47,646	52,763	55,734	58,877	60,560
26	**Energy Utilization Group**							
27	Beginning of Year	5,924	6,442	6,442	7,562	9,664	11,385	11,385
28	Add: Additions	-	-	1,122	2,102	1,721	-	-
29	Less: Disposals and Transfers	-	-	2	0	0	0	0
30	End of Year	5,924	6,442	7,562	9,664	11,385	11,385	11,385
31	**Insurance Proceeds**							
32	Beginning of Year	(13,139)	(13,139)	(13,139)	(13,139)	(13,139)	(13,139)	(13,139)
33	Add: Additions	-	-	-	-	-	-	-
34	Less: Disposals and Transfers	-	-	-	-	-	-	-
35	End of Year	(13,139)	(13,139)	(13,139)	(13,139)	(13,139)	(13,139)	(13,139)
36	**Total Beginning of Year Gross Plant in Service**	**447,165**	**418,145**	**443,558**	**463,099**	**485,730**	**518,174**	**536,242**
37	**Total End of Year Gross Plant in Service**	**461,116**	**443,558**	**463,099**	**485,730**	**518,174**	**536,242**	**559,043**
38	**Total Mid-Year Gross Plant in Service**	**454,141**	**430,851**	**453,328**	**474,414**	**501,952**	**527,208**	**547,643**

Note: 2013/14 forecast reflects adjustment for Inuvik LNG Storage and Gasification Facility Commissioning.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
ACCUMULATED AMORTIZATION
(in thousands of dollars)

Line No.	Accumulated Amortization by Major FERC Category	2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
1	**Hydro Plant**							
2	Beginning of Year	36,434	32,734	34,780	37,194	39,645	42,266	45,187
3	Add: Amortization and True-Up	2,895	2,640	2,633	2,618	2,910	3,096	3,244
4	Less: Disposals, Transfers and other Adjustments	3,948	493	88	36	156	43	89
	Less: Site Restoration Expenses	-	101	131	132	132	132	132
5	End of Year	35,380	34,780	37,194	39,645	42,266	45,187	48,209
6	**Thermal Plant**							
7	Beginning of Year	67,295	66,799	70,596	74,291	79,573	85,210	91,975
8	Add: Amortization and True-Up	6,247	6,204	6,728	7,094	7,883	8,310	8,662
9	Less: Disposals, Transfers and other Adjustments	-	1,468	2,329	1,101	1,536	835	1,061
	Less: Site Restoration Expenses	605	938	704	710	710	710	710
10	End of Year	72,937	70,596	74,291	79,573	85,210	91,975	98,866
11	**Transmission Plant**							
12	Beginning of Year	26,740	26,733	27,720	28,956	30,234	31,625	33,104
13	Add: Amortization and True-Up	1,278	1,272	1,296	1,349	1,508	1,548	1,599
14	Less: Disposals, Transfers and other Adjustments	-	205	17	27	74	26	41
	Less: Site Restoration Expenses	-	80	43	43	43	43	43
15	End of Year	28,018	27,720	28,956	30,234	31,625	33,104	34,619
16	**Distribution Plant**							
17	Beginning of Year	19,796	19,618	20,314	21,126	21,846	22,492	23,217
18	Add: Amortization and True-Up	955	794	1,021	1,043	838	912	996
19	Less: Disposals, Transfers and other Adjustments	-	83	190	304	173	168	158
	Less: Site Restoration Expenses	-	16	19	19	19	19	19
20	End of Year	20,750	20,314	21,126	21,846	22,492	23,217	24,036
21	**General Plant**							
22	Beginning of Year	17,117	16,164	19,131	21,111	24,104	26,975	30,549
23	Add: Amortization and True-Up	3,362	3,367	3,341	3,557	3,870	4,135	4,358
24	Less: Disposals, Transfers and other Adjustments	-	396	1,265	468	903	465	576
	Less: Site Restoration Expenses	120	5	95	96	96	96	96
25	End of Year	20,358	19,131	21,111	24,104	26,975	30,549	34,236
26	**Energy Utilization Group**							
27	Beginning of Year	2,159	1,600	1,933	2,315	2,633	3,001	3,403
28	Add: Amortization and True-Up	437	352	383	319	368	402	402
29	Less: Disposals, Transfers and other Adjustments	-	19	2	0	0	0	0
	Less: Site Restoration Expenses	-	-	-	-	-	-	-
30	End of Year	2,596	1,933	2,315	2,633	3,001	3,403	3,806
31	**Insurance Proceeds**							
32	Beginning of Year	(7,329)	(7,334)	(7,595)	(7,905)	(8,120)	(8,411)	(8,703)
33	Add: Amortization and True-Up	(215)	(262)	(309)	(215)	(292)	(292)	(292)
34	Less: Disposals, Transfers and other Adjustments	-	-	-	-	-	-	-
35	End of Year	(7,544)	(7,595)	(7,905)	(8,120)	(8,411)	(8,703)	(8,995)
36	**Total Beginning of Year Accumulated Amortization**	**162,211**	**156,315**	**166,878**	**177,088**	**189,915**	**203,157**	**218,732**
37	**Total End of Year Accumulated Amortization**	**172,495**	**166,878**	**177,088**	**189,915**	**203,157**	**218,732**	**234,776**
38	**Total Mid-Year Accumulated Amortization**	**167,353**	**161,596**	**171,983**	**183,501**	**196,536**	**210,944**	**226,754**

Note: 2013/14 forecast reflects adjustment for Inuvik LNG Storage and Gasification Facility Commissioning.

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Customer Contributions

(in thousands of dollars)

Line No.		2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
1	**Customer Contributions Gross Plant**							
2	Beginning of Year	15,690	17,683	18,491	19,852	21,450	21,450	21,450
3	Add: Additions	-	808	1,361	1,597			-
4	Less: Disposals and Transfers	-						-
5	End of Year	15,690	18,491	19,852	21,450	21,450	21,450	21,450
6	**Customer Contributions Accumulated Ammortization**							
7	Beginning of Year	(8,729)	(8,526)	(9,158)	(9,835)	(10,482)	(11,159)	(11,836)
8	Add: Amortization (net of true up adjustment)	(608)	(631)	(616)	(647)	(677)	(677)	(677)
9	Less: True-Up and Transfers	-	-	61				-
10	End of Year	(9,337)	(9,158)	(9,835)	(10,482)	(11,159)	(11,836)	(12,513)
11	**Net Opening Customer Contribution**	**6,961**	**9,157**	**9,333**	**10,017**	**10,968**	**10,291**	**9,614**
12	**Net Ending Customer Contribution**	**6,353**	**9,333**	**10,017**	**10,968**	**10,291**	**9,614**	**8,937**
13	**Net Mid-Year Customer Contribution**	**6,657**	**9,245**	**9,675**	**10,492**	**10,629**	**9,952**	**9,275**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
DEFERRAL ACCOUNTS
(in thousands of dollars)

Line No.		2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	Test Year 2017/18 Forecast	Test Year 2018/19 Forecast
	Add: Regulatory Hearing Cost							
1	Beginning of Year	1,007	1,225	1,191	1,333	1,362	1,850	1,538
2	Additions		222	399	286	1,000	200	
3	Amortization	243	257	257	257	512	512	512
4	End of Year	764	1,191	1,333	1,362	1,850	1,538	1,026
5	**Mid-Year Balance**	**886**	**1,208**	**1,262**	**1,348**	**1,606**	**1,694**	**1,282**
	Add: Overhaul Deferral Account							
6	Beginning of Year	4,038	4,633	4,643	4,959	5,987	7,240	5,806
7	Additions	2,737	2,946	3,252	3,964	5,188	2,500	2,500
8	Amortization	2,936	2,936	2,936	2,936	3,935	3,935	3,935
9	End of Year	3,839	4,643	4,959	5,987	7,240	5,806	4,371
10	**Mid-Year Balance**	**3,938**	**4,638**	**4,801**	**5,473**	**6,614**	**6,523**	**5,088**
	Add: Water Licencing Deferral Account							
11	Beginning of Year	5,281	5,320	5,413	5,638	5,770	5,074	4,429
12	Additions	777	918	1,050	958	915	965	1,000
13	Amortization	825	825	825	825	1,611	1,611	1,611
14	End of Year	5,232	5,413	5,638	5,770	5,074	4,429	3,818
15	**Mid-Year Balance**	**5,256**	**5,367**	**5,526**	**5,704**	**5,422**	**4,751**	**4,123**
	Add: Reserve for Injuries & Damages							
16	Beginning of Year	1,753	1,898	1,228	833	490	240	-10
17	Additions			275	326			
18	Amortization	670	670	670	670	250	250	250
19	End of Year	1,083	1,228	833	490	240	-10	-260
20	**Mid-Year Balance**	**1,418**	**1,563**	**1,031**	**661**	**365**	**115**	**-135**
	Add: Employee Benefits							
21	Beginning of Year	2,142	2,556	2,749	3,189	3,135	2,835	2,535
22	Additions	134	541	788	294	500	500	500
23	Amortization	348	348	348	348	800	800	800
24	End of Year	1,928	2,749	3,189	3,135	2,835	2,535	2,235
25	**Mid-Year Balance**	**2,035**	**2,653**	**2,969**	**3,162**	**2,985**	**2,685**	**2,385**
26	**Total Mid-Year Deferral Accounts**	**13,534**	**15,428**	**15,588**	**16,348**	**16,992**	**15,768**	**12,743**

Schedule 11.5

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
DEFERRED EXPENSES
(in thousands of dollars)

Line No.		2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	Test Year 2017/18 Forecast	Test Year 2018/19 Forecast
	Add: Deferred Expenses							
1	Beginning of Year	798	1,711	1,588	1,902	2,350	2,170	1,851
2	Additions		21	465	601	90	50	50
3	Amortization	133	143	152	153	271	369	369
4	End of Year	665	1,588	1,902	2,350	2,170	1,851	1,532
5	**Mid-Year Balance**	**732**	**1,650**	**1,745**	**2,126**	**2,260**	**2,010**	**1,691**
	Feasibility Studies							
	Beginning of Year	761	1,791	1,382	2,074	1,554	1,137	882
	Additions	-	-	1,144	-	70	245	-
	Amortization	193	409	452	520	487	501	332
	End of Year	568	1,382	2,074	1,554	1,137	882	549
	Mid-Year Balance	**665**	**1,586**	**1,728**	**1,814**	**1,346**	**1,010**	**716**
31	**Total Mid-Year Deferred Expenses**	**1,396**	**3,236**	**3,473**	**3,940**	**3,606**	**3,020**	**2,407**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Construction Work in-Progress Continuity Schedule ($000)

Schedule 11.6

Project Name	2013/14 GRA Capital Addition	2013/14 Actual					2014/15 Actual				
		Opening CWIP Balance	2013/14 Expenditures	OH Earned 17%	IDC Earned @ 5.68%	2014 Capital Addition	Opening CWIP Balance	2014/15 Expenditures	OH Earned 22%	IDC Earned @ 5.68%	2015 Capital Addition
Snare System Transient Stability Upgrade	(3,264)	1,868	779	121	39	(1,362)	1,444	654	144	41	(2,283)
Road and Airstrip Improvements	(644)										
Recommendations from 2011 DSR	(268)	89	131	22		(242)					
Fort Smith Distribution System Upgrade	(1,607)	962	355	71	37		1,425	(13)			(1,412)
New Garage/Warehouse/Office	(793)										
Jean Marie River Engine Replacement (Engine DD 4-71)	(472)	148	399	67	17		631	88	19	17	(756)
Automation/PLC Installation	(269)		149	25	5		179		(27)	5	(127)
Replace Engine DD 4-71 - First Engine	(579)										
Jean Marie River 3 Phase Automation & Breaker Upgrade	(972)		744	126	24		895	7	2	25	(928)
Inuvik K-Plant Combustion Air Upgrade	(286)	74	2		2		78	33	7	3	
Inuvik Tank "F" Bulk Fuel Storage Upgrade	(1,184)	46	1,315	208		(1,569)		392	86	12	
Replace Snare Falls RTU	(333)	176	83	36		(295)					
Replace Snare Tie Sub RTU	(263)	207	26	3		(236)					
CMMS	(413)	62	931	159	31		1,182	730	161	89	
Install Custody Transfer Meters	(268)										
T&D Group - Vehicle and Machinery Purchases	(456)										
Replace Jackfish Plant RTU	(243)	131	215	36		(382)					
Behchoko Modular Two Megawatt Diesel Generator		144	1,898	322	67		2,431	194	42	75	(2,741)
Fort Smith Bucket Truck		1	299	25		(326)					
Bucket Truck Storage Facility			413	70	1	(375)	109	166	36	1	(313)
Fort Good Hope Engine Replacement		421			12	(433)					
Install 2.8MW EMD		2,655	120	106	58	(2,939)					
Convert Wartsila Gas Engines		1,706	3,608	433	48	(5,795)					
LNG Storage			5,261	735		(5,996)					
Inuvik G6 Auto Start		154	481	82	4	(721)					
Upgrade Tank Farm Underground Pipeline		540	339	57	15	(952)					
Construction Engine Block Repl			266	45		(311)					
Business Reporting Tool		348	106	18	9	(481)					
Jackfish T10 Transformer Refurbishment			291	49	8		348	5	1	18	
Duncan Dam Upgrades		5	36	6	1		48	414			(457)
Fort Smith Load Bank		7	166	28	6		207	66	13	8	
Gameti Engine Replacement & Plant Heat Recovery			135	23	4		163	910	200	5	(1,277)
Inuvik General Cleanup (Reliability Improvement)		40	232	39	9		319	268	59	9	(654)
Inuvik Road Widening			101	17	3		122	339	76	2	(539)
CAT D353 Engine Replacement			342	58	11		412	445	117	14	(914)
North Slave Protective Relay Upgrade		9	434	36	14		492	143	32	1	(416)
Selection and Installation of Lone Worker System			23	4	1		28	289	64	11	
Jackfish Green Jacket Coverups			168	29	6		202	6		6	
Snare Transmission Lightning Protection			43	6	1		51	20	1	2	
Snare Cascades New Electronic Governor			22	4	1		26	1		1	
Jackfish T4 Transformer Upgrade		14	83	14	3		114	25	6	7	
Norman Wells Plant Heating Conversion			197	34	6		237	201	9	2	(392)
Snare Falls Mechanical Overhaul								307	6	1	
Sewage Lift Station								236	52		(288)
Colville Lake Modular Power Plant								4,521	914	151	(468)
North Slave Two Megawatt Mobile Diesel Generator								1,124	247		(1,366)
Jean Marie River Fuel System Upgrade								113			
Inuvik 5kV Breaker Replacement								179	39	7	
Capital Lease								4	1		
Snare 5B Spillway Repairs								9	2	1	
Snare Cascades Spillway								16	3	1	
Bluefish Line Bird Deterrents								35	7	5	
Ulukhatok Main Fuel Storage Tank								46	9	2	
Distribution Line to PV Site								214	47	8	
Nahanni Butte Fuel System Upgrade								102	18		
Inuvik New Exhaust Gas Recover Unit								44	10	1	
Jackfish Mirrlees Replacement											
2016 Replace/Upgrade IT Equipment											
Jackfish T3 Transformer Replacement											
Bucket Truck											
LED Streetlight Upgrades											
Tulita Day Fuel Tank											
Inuvik New Station PLC											
Jackfish Control System Upgrades											
Aklavik Variable Speed Generator											
Upgrade L191 Deteriorated Structures											
Fort Smith Intelligent Metering Hub (IMH)											
Fort Resolution Rebuild Distribution Feeder											
Fibre Optic Cable Upgrade											
Server and Storage Replacements											
Cat Plant Lube Oil Storage											
Study to Remove old Administration Building											
Paulatuk New Living Accommodations											
Jackfish SCADA System Replacement											
Jackfish - UPS systems upgrade											
Block Replacement G2 (Guascor)											
Ventilation Upgrade											
New Multilins for G1/2/3/SS/F1 & F2											
IMH Metering Hubs											
Protection Upgrade, Multilins and Breakers											
Snare Rapids - Excitation System Upgrade											
New EMD Vibration Isolators (G3/G7/G8)											
Roof Replacement Head Office											
Norman Wells Plant Replacement											
Nahanni Butte Engine Replacement											
Jean Marie River G3 Engine Replacement											
Spillway 5B Transmission Line											
Jackfish T5 Reactor Bank/transformer Replacement											
Snare Forks Hydro Unit Overhaul											
New Transient Trailer											
Inuvik Paint F Tank											
Purchase digger truck											
Jackfish - K-Plant Upgrade G1/G4 Cooling sytem upgrade											
Capital less than $250,000	(5,586)	5,004	5,557	559	155	(4,260)	7,014	4,526	373	(170)	(7,201)
Grand Total	**(17,900)**	**14,810**	**25,749**	**3,673**	**599**	**(26,675)**	**18,156**	**16,862**	**2,776**	**359**	**(22,533)**
Customer contribution jobs						**(975)**					**(693)**
Capital Inventory						**(391)**					**(212)**
Total						**(28,041)**					**(23,439)**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Construction Work in-Progress Continuity Schedule ($000)

Schedule 11.6

Project Name	2015/16 Forecast					2016/17 Forecast				
	Opening CWIP Balance	2015/16 Expenditures	OH Earned 22%	IDC Earned @ 5.68%	2016 Capital Addition	Opening CWIP Balance	2016/17 Expenditures	OH Earned 22%	IDC Earned @ 5.53%	2017 Capital Addition
Snare System Transient Stability Upgrade										
Road and Airstrip Improvements										
Recommendations from 2011 DSR										
Fort Smith Distribution System Upgrade										
New Garage/Warehouse/Office										
Jean Marie River Engine Replacement (Engine DD 4-71)										
Automation/PLC Installation	30	4	1	1	(35)					
Replace Engine DD 4-71 - First Engine										
Jean Marie River 3 Phase Automation & Breaker Upgrade										
Inuvik K-Plant Combustion Air Upgrade	121	17	4	4		146			4	
Inuvik Tank "F" Bulk Fuel Storage Upgrade	490	128	28	14	(660)					
Replace Snare Falls RTU										
Replace Snare Tie Sub RTU										
CMMS	2,161	941	207	61	(3,371)		586	129		(715)
Install Custody Transfer Meters										
T&D Group - Vehicle and Machinery Purchases										
Replace Jackfish Plant RTU										
Behchoko Modular Two Megawatt Diesel Generator										
Fort Smith Bucket Truck										
Bucket Truck Storage Facility										
Fort Good Hope Engine Replacement										
Install 2.8MW EMD										
Convert Wartsila Gas Engines										
LNG Storage										
Inuvik G6 Auto Start										
Upgrade Tank Farm Underground Pipeline										
Construction Engine Block Repl										
Business Reporting Tool										
Jackfish T10 Transformer Refurbishment	373	89	19	11	(491)					
Duncan Dam Upgrades	5					5				
Fort Smith Load Bank	295	218	48	16		577	104	23	16	(719)
Gameti Engine Replacement & Plant Heat Recovery										
Inuvik General Cleanup (Reliability Improvement)										
Inuvik Road Widening										
CAT D353 Engine Replacement	73	229	50	2	(354)					
North Slave Protective Relay Upgrade	253	133	29	7	(423)		30	6		(36)
Selection and Installation of Lone Worker System	392	215	47	11	(665)					
Jackfish Green Jacket Coverups	214			6		220	61	13	6	(300)
Snare Transmission Lightning Protection	74	274	23	11		383	625	137	11	(1,155)
Snare Cascades New Electronic Governor	28	117		4		148	1,924	423	4	(2,500)
Jackfish T4 Transformer Upgrade	152	4		4		162	68	15	7	
Norman Wells Plant Heating Conversion	57	98	22	2	(178)					
Snare Falls Mechanical Overhaul	314	5,996	1,319	217		7,845	735	162	217	(8,958)
Sewage Lift Station										
Colville Lake Modular Power Plant	5,117	1,343	295	145	(6,900)					
North Slave Two Megawatt Mobile Diesel Generator	5	110	24		(139)					
Jean Marie River Fuel System Upgrade	113	351	77	3	(543)					
Inuvik 5kV Breaker Replacement	225	188	41	6	(367)	94			3	(80)
Capital Lease	4	230	51		(285)					
Snare 5B Spillway Repairs	12	268	59		(339)					
Snare Cascades Spillway	20	323	71	1	(414)					
Bluefish Line Bird Deterrents	48	178	39	1	(266)					
Ulukhatok Main Fuel Storage Tank	57					57	453	100		(552)
Distribution Line to PV Site	269	115	25	8	(416)					
Nahanni Butte Fuel System Upgrade	121					121			3	
Inuvik New Exhaust Gas Recover Unit	54	16	1	2		73			2	
Jackfish Mirrlees Replacement		2,103	461	73		2,636	3,093	681	73	(6,483)
2016 Replace/Upgrade IT Equipment		262	58		(320)					
Jackfish T3 Transformer Replacement		1,000	220		(1,220)					
Bucket Truck		257	57		(314)					
LED Streetlight Upgrades		357	79		(435)					
Tulita Day Fuel Tank		48	4		(51)					
Inuvik New Station PLC		26	2		(27)		116	25	4	
Jackfish Control System Upgrades		2			(2)		140	31	5	
Aklavik Variable Speed Generator							1,188	261		(1,449)
Upgrade L191 Deteriorated Structures							246	54		(300)
Fort Smith Intelligent Metering Hub (IMH)							535	118		(653)
Fort Resolution Rebuild Distribution Feeder							490	108		(598)
Fibre Optic Cable Upgrade							226	50		(275)
Server and Storage Replacements							279	61		(340)
Cat Plant Lube Oil Storage							232	51		(283)
Study to Remove old Administration Building							49	11	2	
Paulatuk New Living Accommodations							202	44	7	
Jackfish SCADA System Replacement							200	44	7	
Jackfish - UPS systems upgrade							222	49	7	
Block Replacement G2 (Guascor)										
Ventilation Upgrade										
New Multilins for G1/2/3/SS/F1 & F2										
IMH Metering Hubs										
Protection Upgrade, Multilins and Breakers										
Snare Rapids - Excitation System Upgrade										
New EMD Vibration Isolators (G3/G7/G8)										
Roof Replacement Head Office										
Norman Wells Plant Replacement										
Nahanni Butte Engine Replacement										
Jean Marie River G3 Engine Replacement										
Spillway 5B Transmission Line										
Jackfish T5 Reactor Bank/transformer Replacement										
Snare Forks Hydro Unit Overhaul										
New Transient Trailer										
Inuvik Paint F Tank										
Purchase digger truck										
Jackfish - K-Plant Upgrade G1/G4 Cooling sytem upgrade										
Capital less than $250,000	4,542	7,200	789	136	(7,453)	5,213	7,132	1,569	146	(9,397)
Grand Total	**15,619**	**22,838**	**4,152**	**746**	**(25,669)**	**17,685**	**18,934**	**4,165**	**522**	**(34,793)**
Customer contribution jobs										
Capital Inventory					**1,101**					**(494)**
Total					**(24,568)**					**(35,287)**

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
Construction Work in-Progress Continuity Schedule ($000)

Schedule 11.6

Project Name	2017/18 Forecast					2018/19 Forecast					
	Opening CWIP Balance	2017/18 Expenditures	OH Earned 22%	IDC Earned @ 5.36%	2018 Capital Addition	Opening CWIP Balance	2018/19 Expenditures	OH Earned 22%	IDC Earned @ 5.26%	2019 Capital Addition	Closing CWIP Balance
Snare System Transient Stability Upgrade											
Road and Airstrip Improvements											
Recommendations from 2011 DSR											
Fort Smith Distribution System Upgrade											
New Garage/Warehouse/Office											
Jean Marie River Engine Replacement (Engine DD 4-71)											
Automation/PLC Installation											
Replace Engine DD 4-71 - First Engine											
Jean Marie River 3 Phase Automation & Breaker Upgrade											
Inuvik K-Plant Combustion Air Upgrade	150	517	114	4	(784)						
Inuvik Tank "F" Bulk Fuel Storage Upgrade											
Replace Snare Falls RTU											
Replace Snare Tie Sub RTU											
CMMS		316	69		(385)						
Install Custody Transfer Meters											
T&D Group - Vehicle and Machinery Purchases											
Replace Jackfish Plant RTU											
Behchoko Modular Two Megawatt Diesel Generator											
Fort Smith Bucket Truck											
Bucket Truck Storage Facility											
Fort Good Hope Engine Replacement											
Install 2.8MW EMD											
Convert Wartsila Gas Engines											
LNG Storage											
Inuvik G6 Auto Start											
Upgrade Tank Farm Underground Pipeline											
Construction Engine Block Repl											
Business Reporting Tool											
Jackfish T10 Transformer Refurbishment											
Duncan Dam Upgrades	5					5					6
Fort Smith Load Bank											
Gameti Engine Replacement & Plant Heat Recovery											
Inuvik General Cleanup (Reliability Improvement)											
Inuvik Road Widening											
CAT D353 Engine Replacement											
North Slave Protective Relay Upgrade											
Selection and Installation of Lone Worker System											
Jackfish Green Jacket Coverups											
Snare Transmission Lightning Protection											
Snare Cascades New Electronic Governor											
Jackfish T4 Transformer Upgrade	251	327	72	7	(656)						
Norman Wells Plant Heating Conversion											
Snare Falls Mechanical Overhaul											
Sewage Lift Station											
Colville Lake Modular Power Plant											
North Slave Two Megawatt Mobile Diesel Generator											
Jean Marie River Fuel System Upgrade											
Inuvik 5kV Breaker Replacement	17	52	11		(80)						
Capital Lease											
Snare 5B Spillway Repairs											
Snare Cascades Spillway											
Bluefish Line Bird Deterrents											
Ulukhatok Main Fuel Storage Tank	57					57					57
Distribution Line to PV Site											
Nahanni Butte Fuel System Upgrade	124	638	140	3	(905)						
Inuvik New Exhaust Gas Recover Unit	75	1,390	306	2	(1,773)						
Jackfish Mirrlees Replacement											
2016 Replace/Upgrade IT Equipment											
Jackfish T3 Transformer Replacement											
Bucket Truck											
LED Streetlight Upgrades											
Tulita Day Fuel Tank		468	103		(570)						
Inuvik New Station PLC	145	284	62	4	(495)						
Jackfish Control System Upgrades	175	574	126	5	(880)						
Aklavik Variable Speed Generator											
Upgrade L191 Deteriorated Structures											
Fort Smith Intelligent Metering Hub (IMH)											
Fort Resolution Rebuild Distribution Feeder											
Fibre Optic Cable Upgrade											
Server and Storage Replacements											
Cat Plant Lube Oil Storage											
Study to Remove old Administration Building	61	236	52	2	(350)						
Paulatuk New Living Accommodations	253	131	29	7	(419)						
Jackfish SCADA System Replacement	250	1,040	229	7	(1,516)	10	312	69		(390)	
Jackfish - UPS systems upgrade	278	35	8	7	(328)						
Block Replacement G2 (Guascor)		283	62		(345)						
Ventilation Upgrade		283	62		(345)						
New Multilins for G1/2/3/SS/F1 & F2		259	57		(315)						
IMH Metering Hubs		820	180		(1,000)		820	180		(1,000)	1
Protection Upgrade, Multilins and Breakers		313	69		(381)						
Snare Rapids - Excitation System Upgrade		495	109		(604)						
New EMD Vibration Isolators (G3/G7/G8)		205	45		(250)						
Roof Replacement Head Office		410	90		(500)						
Norman Wells Plant Replacement		798	176	26		1,000	3,771	830	26	(4,600)	1,026
Nahanni Butte Engine Replacement		70	15	2		87	445	98	2	(632)	
Jean Marie River G3 Engine Replacement		68	15	2		85	441	97	2	(625)	
Spillway 5B Transmission Line		160	35	5		200	839	185	5	(1,229)	
Jackfish T5 Reactor Bank/transformer Replacement		80	18	3		100	563	124	3	(789)	
Snare Forks Hydro Unit Overhaul		200	44	7		250	6,234	1,372	7	(7,862)	
New Transient Trailer							320	70		(390)	
Inuvik Paint F Tank							480	106		(585)	
Purchase digger truck							287	63		(350)	
Jackfish - K-Plant Upgrade G1/G4 Cooling sytem upgrade							649	143		(791)	
Capital less than $250,000	4,663	5,730	1,261	127	(6,724)	5,056	4,070	895	135	(5,483)	4,673
Grand Total	**6,514**	**16,176**	**3,559**	**220**	**(19,605)**	**6,864**	**19,229**	**4,230**	**181**	**(24,726)**	**5,777**
Customer contribution jobs											
Capital Inventory											
Total					**(19,605)**					**(24,726)**	

Schedule 11.7

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
WORKING CAPITAL REQUIREMENT
(in thousands of dollars)

Line No.		2013/14 Forecast	2013/14 Actual	2014/15 Actual	2015/16 Forecast	Test Year 2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
1	**Cash Working Capital**	**1,340**	**1,323**	**1,454**	**1,333**	**1,655**	**1,673**	**1,693**
	Add: Supplies Inventory							
2	Beginning of Year	4,261	5,206	5,764	6,067	4,494	5,200	5,200
3	Less: Capital Inventory	2,982	3,644	4,035	4,247	3,146	3,640	3,640
4	Net Beginning of Year	1,278	1,562	1,729	1,820	1,348	1,560	1,560
5	End of Year	4,446	5,764	6,067	4,494	5,200	5,200	5,200
6	Less: Capital Inventory	3,112	4,035	4,247	3,146	3,640	3,640	3,640
7	Net End of Year	1,334	1,729	1,820	1,348	1,560	1,560	1,560
8	**Mid-Year Balance**	**1,306**	**1,646**	**1,775**	**1,584**	**1,454**	**1,560**	**1,560**
9	**Fuel & Lube Average Monthly Balance**	**140**	**297**	**314**	**258**	**260**	**260**	**260**
10	**Total Mid-Year Working Capital Requirement**	**2,786**	**3,265**	**3,542**	**3,174**	**3,369**	**3,493**	**3,513**

CHAPTER 12

AFFILIATE TRANSACTIONS

12.0 INTRODUCTION

The Corporation budgets and tracks costs associated with affiliates by separate plant numbers. The costs are readily separated from regulated activities and are not included in the Corporation's Revenue Requirement. Employee direct costs charged to affiliates are tracked by timesheet. Shared services include building leases, telecommunication costs and computer software costs and are tracked by square footage and costs per employee. Overhead costs are budgeted annually by the Corporation as part of its regular O&M budgeting process. Interest expense is from intercompany loans and is due on demand bearing interest at prime less 50 basis points. In the past, the Corporation has approved a dividend amount to fund the operations of affiliate companies.

The majority of the costs shown in Schedule 12 are from NTEC (03). The mission of NTEC (03) is to plan and develop safe and environmentally responsible energy projects to serve existing and new energy requirements for the NWT. It would carry out initiatives and programs directed by the shareholder, the GNWT. In 2014/15, the GNWT issued a directive for the operations of NTEC (03) to be brought under the Petroleum Products Division of Public Works and Services, effective April 1, 2015. This included all existing contracts NTEC (03) had with suppliers and all direct NTEC

(03) personnel. After March 31, 2015, the only affiliate costs remaining for the Corporation are its share of Aadrii Ltd., a residual heat project in Fort McPherson.

Schedule 12.0

NORTHWEST TERRITORIES POWER CORPORATION
2016/19 GENERAL RATE APPLICATION
AFFILIATE TRANSACTIONS
(in thousands of dollars)

					Test Year		
Transaction Description	**2013/14 Forecast**	**2013/14 Actual**	**2014/15 Actual**	**2015/16 Forecast**	**2016/17 Forecast**	**2017/18 Forecast**	**2018/19 Forecast**
NTPC Direct Costs	233	107	103	12	5	5	5
NTPC Utility Bills	9	10	11	5	10	10	10
Overhead Costs	75	203	174				
Shared Services	164	93	116				
Interest Expense	136	116	48				
Dividends declared to non-regulated entities	400	400	360				
Dividend paid to non-regulated entities	400	454	339				

CHAPTER 13

BOARD DIRECTIVES

13.0 BOARD DIRECTIVES

13.1 DECISION 1-2013

Directive 24: The Board directs NTPC to provide business cases in support of major capital projects forecast to be added to rate base, at the time of the next GRA. The Board finds the list of items to be addressed in business cases as set out by YK/HR provides a reasonable template for structuring business cases. For the purpose of preparing business cases, the Board accepts YK/HR recommendation that the project cost threshold for business cases be set at $400,000.

Response:

Business cases for projects with budgets of $400,000 or higher are included in Chapter 14 of the Application.

Directive 25: NTPC is directed to prepare business cases for capital projects meeting the above threshold and are to commence after March 31, 2013 and, be prepared to provide detailed explanations for variances between budget and actual costs based on post completion reports.

Response:

Business cases for projects with budgets of $400,000 or higher are included in Chapter 14 of the Application.

Directive 27: The Board directs NTPC to provide a post completion report with respect to the Bluefish Dam replacement project at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in

the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant..

Response:

A project completion report for the Bluefish Dam replacement project is included in Chapter 14 of the Application.

Directive 28: The Board is concerned that inclusion of deferred costs under the category of deferral accounts and under the category of plant in service can result in confusion and errors in the testing and evaluation of such costs. Accordingly, NTPC is directed to include deferred costs under an appropriate FERC account at the time of the next GRA.

Response:

Deferred expenses are summarized on Schedule 11.5 separately from deferral accounts (Schedule 11.4).

Directive 29: The Board directs NTPC to provide a cash working capital calculation based on a sampling of leads and lags at the time of the next GRA. This means any revenues related to late payment charges should also be included in other revenues.

Response:

The Corporation has included a lead-lag study in section 14 of the application. The updated lead-lag days have been used to calculate the cash working capital provision in Schedule 11.7. A forecast of interest on overdue accounts is included in other revenues in Schedule 10.0.

Directive 30: Noting the uncertainties over the split in the accumulated amortization balance discussed above, the Board directs NTPC to provide evidence to support the split between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage at the time of the next GRA.

Response:

The Corporation has reviewed the split in the accumulated amortization balance. The split between accumulated amortization of original cost of assets and accumulated amortization related to net salvage is reflected in the depreciation study included in section 14 of the application.

Directive 31: The Board continues to be concerned by an RSF mechanism which allows pass through of all diesel costs as this may not provide the appropriate incentive for NTPC to maximize use of the hydro resource. The Board directs NTPC to address the feasibility of NTPC assuming forecast risk on diesel volume variances for the Snare Zone at the time of the next GRA.

Response:

NTPC has reviewed the possibility of separating out diesel generation related to certain types of operational diesel fuel requirements. NTPC reviewed the treatment of such costs by other Canadian utilities that maintain similar funds. NTPC understands that, other than adjustments for diesel generation related to major capital projects or major disasters such as forest fires, the other utilities use actual generation for their funds and do not make adjustments for other operational considerations.

In NTPC's view, it would be a difficult and largely subjective task to review and categorize a portion of actual diesel generation that should not be charged to the stabilization fund. Therefore the Corporation is not proposing any adjustments to the stabilization fund mechanics at this time.

Directive 32: The Board directs NTPC to examine the following refinements with respect to its UPC forecast methodology for the purposes of the next GRA:

- **For those communities where temperature normalization data is available, NTPC is to carry out regression analyses for all temperature sensitive**

sales, using degree days, trend variable(s) and any other relevant variables to develop a reasonable estimate of forecast UPC.

- **For those communities where temperature normalization data is not available, NTPC is to use a straight 5 year average UPC over the most recent recorded (actual) years and use the actual growth rate over the same recorded years to project growth for the forecast years.**

Response:

The Corporation has updated its load forecast methods consistent with this directive. The revised methods are described in Chapter 2 of this application. Monthly Heating Degree Day (HDD) data are available for Colville Lake, Deline, Fort Good Hope, Fort Liard, Fort Simpson, Fort Smith, Inuvik, Lutsel K'e, Norman Wells, Paulatuk, Tuktoyaktuk, Sachs Harbour, Ulukhaktok and Wha Ti. For these communities, the Corporation developed a weather normalized use per customer (UPC) for residential and general service customers using the following method:

Step 1: Summarize HDD data by month by community for five years; April 2011 through March 2016. The HDD data was obtained from Government of Canada Monthly Climate Summaries for each community [available at http://climate.weather.gc.ca/prods_servs/cdn_climate_summary_e.html].

Step 2: Regression analysis using actual monthly UPC for April 2011 through March 2016 [March 2016 forecast sales] as dependent and HDD data for the same period as independent values.

This step was repeated for residential and general service rate classes separately for each community with HDD data. The regression analysis provides correlation

coefficients between HDD and actual UPC. Variable coefficient was used in the next step.

Step 3: Calculate temperature normalized UPC for each month from April 2011 through March 2016 using HDD data and regression outcomes. The following formula illustrates the approach for calculating temperature normalized UPC:

Monthly Temperature Normalized UPC = Actual Monthly UPC + [5-year average HDD – HDD for the current month] x Coefficient [from Step 2].

Step 4: Use temperature normalized UPC in the load forecast based on a 5-year rolling average UPC.

Using temperature normalized UPCs did not materially alter the results of the forecasts compared to using a simple 5-year average UPC. Table 13.1 illustrates differences in the sales forecasts for residential and general service customers using a simple 5-year average UPC approach and a temperature normalized UPC approach.

Table 13.1

Impact of Temperature Normalized UPC on Load Forecast

	Residential and General Service Sales Forecast			
	Using 5-year Rolling Average Actual UPC, MW.h	Using 5-year Rolling Average Temperature Normalized UPC, MW.h	Difference, MW.h	Difference, %
	A	B	C=B-A	D=B/A-1
Fort Smith				
2016/17	61,969	61,969	-	0.0%
2017/18	62,034	61,954	(80)	-0.1%
2018/19	61,904	61,912	8	0.0%
Inuvik				
2016/17	47,076	47,076	-	0.0%
2017/18	47,089	47,177	87	0.2%
2018/19	46,970	47,096	127	0.3%

Directive 33: The Board notes YK/HR concern that capital additions such as Line Tools, Hot Sticks, Truck equipment, and major tool purchases, Type 6 work as well as certain vehicle and machinery purchases are budgeted at corporate; yet the actual costs are eventually recorded in the communities that are served. The Board agrees the type of costs referred to by YK/HR are not common costs but rather, zone specific costs and should be assigned to each zone on a forecast basis using reasonable assumptions. NTPC is directed to reflect this direction in future GRA filings.

Response:

The assignment of costs to each zone provided in the Phase I application is prepared for illustrative purposes only. A more detailed assignment of costs to each zone will be completed as part of the cost of service study in NTPC's Phase II General Rate Application.

13.2 DECISION 9-2013

Directive 1: The Board notes the onus is upon NTPC to justify the level of IDC requested on major spares when they are added to rate base as part of a capital project. However, the Board is cognisant of the potential for IDC on major spares additions to become subsumed under broader categories of asset additions unless they are separately identified and linked to the particular capital project they are part of. Accordingly, NTPC is directed to provide a separate continuity schedule of major spares showing opening balances, annual expenditures, IDC amounts, transfers to rate base by project, and closing balances, in future GRAs.

Response:

Table 13.2 provides a continuity Schedule for IDC charged on major spare parts. The Schedule shows the amount of IDC related to items in inventory that have been issued to capital and form part of ratebase. The Corporation's proposed method for recovering these IDC costs is provided in section 11 of the application.

Table 13.2

Continuity Schedule of IDC on Major Spare Parts

		2008-09			2009-10			2010-11			2011-12			2012-13			2013-14			2014-15		
Item #	Description	Value of Inv Mar 2008	IDC added to Inv @ 9.674%	IDC on inventory issued to capital	Value of Inv Mar 2009	IDC added to Inv @ 9.674%	IDC on inventory issued to capital	Value of Inv Mar 2010	IDC added to Inv @ 9.674%	IDC on inventory issued to capital	Value of Inv Mar 2011	IDC added to Inv @ 9.674%	IDC on inventory issued to capital	Value of Inv Mar 2012	IDC added to Inv @ 6.540%	IDC on inventory issued to capital	Value of Inv Mar 2013	IDC added to Inv @ 5.680%	IDC on inventory issued to capital	Value of Inv Mar 2014	IDC added to capital @ 5.680%	IDC on inventory issued to capital
1002541	Tower Guyed Alluminum Type B										8,880	1,718		9,739	1,274		10,376	1,182		10,967	727	
1006154	Engine Detroit Diesel 60 Series 14 L Model 6063 HK35 cw Generator	78,938	3,818		82,757	8,006		90,762	8,780		99,543	9,630		109,173	7,140		116,312	6,624		122,937	4,655	
1006233	Tower A Tangent Steel Lattice										21,078	4,078		23,117	3,024		24,629	2,805		26,031	1,971	
1006234	Tower B Angle Steel Lattice										14,274	2,762		15,655	2,048		16,679	1,900		17,629	1,335	
1006235	Tower D Deadend Steel Lattice										14,028	2,714		15,385	2,012		16,391	1,867		17,324	1,312	
1006829	Engine Block Detroit Series 60 14 Liter	31,317	1,515		32,832	4,539		36,246	3,506		39,751	3,846		43,597	2,851		46,448	2,645		49,093	1,859	
1008025	Engine Detroit Diesel LD70295 U672497A							30,863	2,986		33,848	3,275		37,123	2,428		39,551	2,252		41,803	1,583	
1008351	Engine Block Detroit Series 60 Serial# 06R1037912										34,107	3,299		38,082	2,491		41,069	2,339		43,972	1,665	
1008355	Engine Block Detroit Series 60 Serial# 06R1037907										34,107	3,299		38,082	2,491		41,069	2,339		43,972	1,665	
1008356	Engine Block Detroit Series 60 Serial# 06R1037911										34,107	3,299		38,082	2,491		41,069	2,339		43,972	1,665	
1008358	Engine Block Detroit Series 60 Serial# 06R1037905										34,107	3,299		38,082	2,491		41,069	2,339		43,972	1,665	
1008361	Engine Block Detroit Series 60 Serial# 06R1037906										34,107	3,299		38,082	2,491		41,069	2,339		43,972	1,665	
1008371	Engine Isuzu 6BG1-TQV 396.6 CI													15,997	436		16,433	879		17,847	676	
1008508	Sewage Treatment System							204,362	14,828		219,190	21,204		240,394	15,722							
1008527	Engine EMD 20-645-E4													621,976	51,165		673,141	38,335		711,477	26,941	
1006047	(Issued) Engine Block Isuzu Model 6BGIT 396.6CI	9,033	437		9,470	1,263	1,700	9,761	944		11,894	1,151		13,045	421	2,516						
1006238	(Issued) Engine Detroit Diesel 60 Series 12.7L Model 6063 MK35 c/w generator	94,579	4,575		99,153	9,592		108,746	2,630	16,797												
1006832	(Issued) Engine EMD model L20-645F4B Serial 89K1-1043 cw Generator							889,943	86,093		976,036	94,422		1,070,457	34,519	215,033						
1008022	(Issued) Generator Baylon G855RNV-333 LK66895-2-B							20,577	1,991		22,568	2,183		24,751	798	4,972						
1008347	(Issued) Engine Block Detroit Series 60 Serial # 06R1037770										34,107	550	550									
1008348	(Issued) Engine Block Detroit Series 60 Serial# 06R1037701										34,107	3,299		38,082	921	4,220						
1008349	(Issued) Engine Block Detroit Series 60 Serial# 06R1037908																					
1008350	(Issued) Engine Block Detroit Series 60 Serial# 06R1037910										34,107	3,299		38,082	2,491	5,790						
1008352	(Issued) Engine Block Detroit Series 60 Serial# 06R1037699										34,107	550	550									
1008353	(Issued) Engine Block Detroit Series 60 Serial# 06R1037704										34,107	3,299		38,082	2,491		41,069	2,339		43,972	416	8,129
1008354	(Issued) Engine Block Detroit Series 60 Serial# 06R1037705										34,107	3,299		38,082	2,491		41,069	2,339		43,972	416	8,129
1008357	(Issued) Engine Block Detroit Series 60 Serial# 06R1037703										34,107	3,299		38,082	2,491		41,069	2,339		43,972	416	8,129
1008359	(Issued) Engine Block Detroit Series 60 Serial# 06R1037706										34,107	3,299		38,082	2,491		41,069	2,339		43,972	416	8,129
1008360	(Issued) Engine Block Detroit Series 60 Serial# 06R1037702										34,107	3,299		38,082	2,491		41,069	978	6,768			
1008376	(Issued) Metering Tank Type MVCT-110 3PH 4 Wire										28,078	2,716		30,794	2,014		32,808	1,868		34,676	657	6,599
1008391	(Issued) Fuel Storage Tank 90,000L										59,533	5,759		65,292	4,270		69,562	669	10,698			
	Total IDC on Inventory Issued to Capital			**0**			**1,700**			**16,797**			**1,100**			**232,532**			**17,466**			**39,114**

Directive 2: Since comparable utility amortization parameters are often considered, among other factors, in establishing NTPC's amortization parameters, use of consistent accounting policies with those of comparable utilities, with respect to treatment of retirements would be desirable. Accordingly, NTPC is directed to address the consistent treatment of retirement units in the context of the SSA/MFR process that is currently under way and reflect the resulting changes, if any, in the GRA filings at the time of the next GRA.

Response:

The Corporation has reflected treatment of retirements in this application consistent with the review conducted during the SSA/MFR process as requested.

Directive 4: The Board considers the cost of lease financing payable by past, current and future customers must be just and reasonable as the mix of the debt and equity financing changes over time. The Board has expressed these concerns in Decision 13-2007 and continues to be concerned by the lack of discussion on this matter. In order to examine this matter in a more structured manner, the Board directs NTPC to provide the following information at the time of the next GRA:

- **Schedule showing the cost and accumulated depreciation balances respecting the 4.3MW DPC hydro asset in NTPC's books, the capital lease obligations and the corresponding cost rates as well as the actual and estimated lease payments, in each year, during the 65 year term of the DPC lease.**

- **NTPC's calculation of DPC's capital lease asset and the financing of the capital lease over the 65 year term of the lease based on initial equity as well as the debt financing initially provided to DPC by NWT Energy Corporation Ltd (NTEC). The Schedule must reflect, for each year, of the 65 year term of the lease, the repayment of the NTEC debt over a 30 year period and the changes to DPC's capital structure as a result of the repayment of the initial debt.**

- **An assessment of the prudence, materiality and fairness of the lease rate in each year, from the perspective of past, current and future customers over the 65 year term of the lease.**

Response:

Table 13.3 provides the actual and estimated capital lease payments for the 65 year term of the Snare Cascades agreement. As noted by the Board in its Decision 1-97, the Snare Cascades project, including the long term lease provisions contained in the Power Acquisition agreement was subject to considerable scrutiny by all parties in terms of interrogatories and intervenor evidence.[1]

With respect to the prudence of the lease payments in each year to customers, the Corporation notes the following:

- As noted at the time of the 1995/98 GRA, a considerable benefit of the agreement to the Corporation and its customers was that the partnership with the Dogrib enabled the planning and environmental licensing of the project to be completed quickly and efficiently. Without such an agreement in place there likely would have been substantial additional planning and licensing costs for the project and a risk that the project could never be developed.
- The Corporation's current cost of diesel fuel in Yellowknife is approximately 19 cents/kWh. This is the pure variable cost of fuel and does not consider the additional capacity costs the Corporation would incur to replace the Snare Cascades generation with diesel generation. The Corporation acquires the energy and capacity benefits of the Snare Cascades project at a substantially lower cost per kWh than the simple variable cost of diesel fuel.

[1] Page 7, Decision 1-97.

On that basis, in NTPC's view the costs associated with the Snare Cascades lease are prudent, reasonable and provide substantial benefits to NTPC's customers (including retail customers of NUL in Yellowknife) throughout the term of the lease agreement.

Table 13.3

Snare Cascades Capital Lease Payments ($000's)

Fiscal Year End	Rate Base	Adjustments	Amortization	Return on Debt Factor	Return on Equity Factor	Dogrib O&M Costs	Water & Ground Lease	Total Lease Payment	Percent Debt	Percent Equity	Debt Cost Rate	Equity Cost Rate
1997	26,115	(22)	260	1,394	241	39	1	1,935	87.77%	12.23%	9.58%	11.25%
1998	25,710	-	405	2,191	343	60	1	3,001	88.58%	11.42%	9.60%	11.25%
1999	25,305	-	405	2,176	315	60	1	2,958	89.36%	10.64%	9.60%	11.25%
2000	24,900	-	405	2,160	289	60	1	2,915	90.10%	9.90%	9.60%	11.25%
2001	24,494	-	405	2,142	260	60	1	2,869	90.79%	9.21%	9.60%	9.25%
2002	24,089	-	405	2,122	199	60	1	2,788	91.42%	8.58%	9.60%	9.25%
2003	23,684	-	405	2,100	182	60	1	2,749	91.99%	8.01%	9.60%	9.25%
2004	23,279	-	405	2,077	168	60	1	2,711	92.47%	7.53%	9.60%	9.25%
2005	22,873	-	405	2,050	156	60	1	2,673	92.85%	7.15%	9.60%	9.25%
2006	22,468	-	405	2,021	146	60	1	2,634	93.12%	6.88%	9.60%	9.25%
2007	22,063	-	405	1,989	140	60	1	2,595	93.26%	6.74%	9.60%	9.25%
2008	21,657	-	405	1,954	135	60	1	2,555	93.24%	6.76%	9.60%	9.00%
2009	21,252	-	405	1,915	132	60	1	2,514	93.04%	6.96%	9.60%	9.00%
2010	20,847	-	405	1,873	136	60	1	2,475	92.63%	7.37%	9.60%	9.00%
2011	20,442	-	405	1,826	143	60	1	2,436	91.97%	8.03%	9.60%	9.00%
2012	20,036	-	405	1,775	155	60	1	2,396	91.04%	8.96%	9.60%	9.00%
2013	19,631	-	405	1,718	157	60	1	2,342	89.77%	10.23%	9.60%	8.25%
2014	19,226	-	405	1,656	177	60	1	2,299	88.14%	11.86%	9.60%	8.25%
2015	18,821	-	405	1,587	203	60	1	2,256	86.07%	13.93%	9.60%	8.25%
2016	18,415	-	405	1,512	234	60	1	2,212	83.51%	16.49%	9.60%	8.25%
2017	18,010	-	405	1,429	272	60	2	2,167	80.37%	19.63%	9.60%	8.25%
2018	17,605	-	405	1,337	317	60	2	2,121	76.57%	23.43%	9.60%	8.25%
2019	17,200	-	405	1,237	370	60	2	2,074	72.01%	27.99%	9.60%	8.25%
2020	16,794	-	405	1,126	432	60	2	2,025	66.58%	33.42%	9.60%	8.25%
2021	16,389	-	405	1,005	503	60	2	1,974	60.14%	39.86%	9.60%	8.25%
2022	15,984	-	405	871	584	60	2	1,922	52.55%	47.45%	9.60%	8.25%
2023	15,579	-	405	723	677	60	2	1,868	43.62%	56.38%	9.60%	8.25%
2024	15,173	-	405	561	783	60	2	1,811	33.16%	66.84%	9.60%	8.25%
2025	14,768	-	405	383	903	60	2	1,753	20.92%	79.08%	9.60%	8.25%
2026	14,363	-	405	187	1,038	60	2	1,692	6.63%	93.37%	9.60%	8.25%
2027	13,958	-	405	15	1,152	60	2	1,634	0.00%	100.00%	0.00%	8.25%
2028	13,552	-	405	-	1,132	60	2	1,599	0.00%	100.00%	0.00%	8.25%
2029	13,147	-	405	-	1,099	60	2	1,565	0.00%	100.00%	0.00%	8.25%
2030	12,742	-	405	-	1,065	60	2	1,532	0.00%	100.00%	0.00%	8.25%
2031	12,336	-	405	-	1,032	60	2	1,498	0.00%	100.00%	0.00%	8.25%
2032	11,931	-	405	-	998	60	2	1,465	0.00%	100.00%	0.00%	8.25%
2033	11,526	-	405	-	965	60	2	1,432	0.00%	100.00%	0.00%	8.25%
2034	11,121	-	405	-	931	60	2	1,398	0.00%	100.00%	0.00%	8.25%
2035	10,715	-	405	-	898	60	2	1,365	0.00%	100.00%	0.00%	8.25%
2036	10,310	-	405	-	865	60	2	1,331	0.00%	100.00%	0.00%	8.25%
2037	9,905	-	405	-	831	60	2	1,298	0.00%	100.00%	0.00%	8.25%
2038	9,500	-	405	-	798	60	2	1,264	0.00%	100.00%	0.00%	8.25%
2039	9,094	-	405	-	764	60	2	1,231	0.00%	100.00%	0.00%	8.25%
2040	8,689	-	405	-	731	60	2	1,198	0.00%	100.00%	0.00%	8.25%
2041	8,284	-	405	-	697	60	2	1,164	0.00%	100.00%	0.00%	8.25%
2042	7,879	-	405	-	664	60	2	1,131	0.00%	100.00%	0.00%	8.25%
2043	7,473	-	405	-	630	60	2	1,097	0.00%	100.00%	0.00%	8.25%
2044	7,068	-	405	-	597	60	2	1,064	0.00%	100.00%	0.00%	8.25%
2045	6,663	-	405	-	564	60	2	1,030	0.00%	100.00%	0.00%	8.25%
2046	6,258	-	405	-	530	60	2	997	0.00%	100.00%	0.00%	8.25%
2047	5,852	-	405	-	497	60	2	964	0.00%	100.00%	0.00%	8.25%
2048	5,447	-	405	-	463	60	2	930	0.00%	100.00%	0.00%	8.25%
2049	5,042	-	405	-	430	60	2	897	0.00%	100.00%	0.00%	8.25%
2050	4,637	-	405	-	396	60	2	863	0.00%	100.00%	0.00%	8.25%
2051	4,231	-	405	-	363	60	2	830	0.00%	100.00%	0.00%	8.25%
2052	3,826	-	405	-	330	60	2	796	0.00%	100.00%	0.00%	8.25%
2053	3,421	-	405	-	296	60	2	763	0.00%	100.00%	0.00%	8.25%
2054	3,015	-	405	-	263	60	2	729	0.00%	100.00%	0.00%	8.25%
2055	2,610	-	405	-	229	60	2	696	0.00%	100.00%	0.00%	8.25%
2056	2,205	-	405	-	196	60	2	663	0.00%	100.00%	0.00%	8.25%
2057	1,800	-	405	-	162	60	2	629	0.00%	100.00%	0.00%	8.25%
2058	1,394	-	405	-	129	60	2	596	0.00%	100.00%	0.00%	8.25%
2059	989	-	405	-	96	60	2	562	0.00%	100.00%	0.00%	8.25%
2060	584	-	405	-	62	60	2	529	0.00%	100.00%	0.00%	8.25%
2061	179	-	405	-	29	60	2	495	0.00%	100.00%	0.00%	8.25%
2062	-	-	145	-	2	21	2	170	0.00%	100.00%	0.00%	8.25%

Directive 5: In view of NTPC's assertion that any inaccuracies resulting from the omission of plant retirements from the forecasts are not significant, the Board will accept NTPC's proposed calculation of mid-year plant and amortization expenses for the purposes of this Decision. However, NTPC is directed to recognize plant retirements in the Test Year forecasts in future GRAs.

Response:

The Corporation has included a forecast of plant retirements in the Test Years in Schedule 11.0.

Directive 6: The Board notes the affiliate cost accumulation and charge out procedures described by NTPC did not provide the required transparency, within the record of the current GRA, as to the total affiliate costs by component and the portion thereof that is being charged to the regulated entity and the portion charged to affiliates. The Board considers the matter of transparency of affiliate charges may best be dealt with in the context of the SSA/MFR process that is currently under way. Accordingly, NTPC is directed to address the matter of transparency of affiliate cost accumulation and charge out in the context of the SSA/MFR process and reflect the resulting changes in the GRA filing at the time of the next GRA.

Response:

Schedule 12.0 summarizes the actual and forecast affiliate transaction costs from 2013/14 through 2018/19.

13.3 DECISION 3-2015

Directive 2: To the extent changes arising from adoption of PSAS for fiscal 2015 may trigger requests for changes to future regulatory accounting and regulatory reporting, NTPC should demonstrate such changes are consistent with sound regulatory principles at the time of NTPC's next GRA. Examples of these principles can be found in statutes, regulatory and court decisions and regulatory texts and include intergenerational equity, minimizing rate volatility and use of historical costs rather than fair market, or any other values. NTPC is directed accordingly.

Response:

Section 1.6 of the application addresses changes related to account standards and practices.

Directive 5: To the extent there are differences between financial statements based on PSAS and the regulatory accounting records and reports, reconciliations would need to be performed. The Board directs NTPC to institute internal mechanisms with necessary checks and balances to facilitate periodic reconciliations for purposes of GRA forecasts and annual reports of finances and operations.

Response:

The Corporation has implemented mechanisms to enable periodic reconciliations between PSAS and regulatory accounting. The Corporation reports reconciliations as part of its annual reports of finances and operations.

13.4 DECISION 7-2015

The Board directs NTPC to address the prudence of the actual and life cycle costs of the Colville Lake plant replacement at the time of the next GRA.

Response:

The Corporation will file a project completion report with the Board prior to the end of the 2016/17 fiscal year.

13.5 DECISION 16-2015

NTPC is directed to provide the following information at the time of the next GRA:

1. Address the prudence of fuel costs, if any, included in the project capital cost as part of any evidence supporting the Snare Falls major overhaul project. The

evidence on fuel costs must demonstrate that the incremental fuel costs calculation is based on the pre-overhaul energy capability of the Snare Falls plant and explain how NTPC ensured the scheduling of the period during which Snare Falls would be unavailable and the duration of that period were prudently managed so as to minimize the cost of replacement power.

2. To the extent the fuel cost incurred with respect to replacement power during the construction period is significant in relation to the total project cost, address the appropriateness of treating the fuel cost element as a deferred expense instead of plant cost, to be amortized over a reasonable period of time having regard to customer rate impacts.

Response:

The Corporation is not proposing to capitalize any fuel expense associated with the Snare Falls overhaul. The forecast capital addition in 2016/17 shown in schedule 11.6 of the Application reflects the forecast cost of the overhaul without any capitalized diesel fuel expense. GNWT funding was available to offset the fuel expense incurred as a result of the overhaul.

13.6 DECISION 6-2016

NTPC is directed to provide a table showing funding commitments as well as the actual/forecast funding paid by GNWT and received by NTPC, at the time of filing the complete 2016/19 GRA.

Response:

The Corporation entered into two contribution agreements (one for $20 million and the second for up to $24 million) with the GNWT for funding to offset expenses incurred related to the extreme low water (ELW) situation on the Snare system. This included additional fuel burned for diesel generation incurred related to overhaul work at the Snare Falls Hydro plant. The availability of this ELW funding from the GNWT avoided

the need for a significant fuel stabilization fund rider. The GNWT ELW funding eliminated the need for the 24 month 3.69 cent stabilization fund rider related to the ELW situation that the Corporation originally applied for in September 2014. This funding provided material benefits to electricity customers during a historic drought period.

The Corporation recorded $14.219 of the initial $20 million contribution in its 2014/15 financial statements as contributions to offset thermal generation expenses related to the ELW. The remaining $5.781 million was recorded as deferred government contributions in 2014/15 to be used to offset ELW thermal generation expenses in 2015/16.[2] The first contribution agreement for $20 million was fully expended in the 2015/16 fiscal year.

The Corporation subsequently entered into a second contribution agreement for up to $24 million to offset ELW related expenses in 2015/16 and 2016/17. At present, as a result of the decline of the price of fuel the Corporation does not anticipate it will require the full $24 million under the second contribution agreement. The funds not required for ELW related expenses available under the second contribution agreement cannot be repurposed and will be returned to the GNWT. Table 13.4 shows the actual and forecast ELW related expenses and the offsetting government contributions in each year. The Corporation will report the government contributions related to the ELW expenses in its

[2] Note 10. 2014/15 Financial Statements.

2015/16 and 2016/17 financial statements in the same manner as the 2014/15 financial statements.

Table 13.4
Extreme Low Water Expenses and Government Contributions
$(000s)

	2014/15 (actuals)	2015/16 (preliminary unaudited)	2016/17 (forecast)	Totals
Expenses				
Fuel, Lube and Other	$14,219	$12,290	$2,750	$29,259
Snare Falls overhaul fuel		$5,888		$5,888
Major Overhauls		$4,830	$650	$5,480
Total	**$14,219**	**$23,008**	**$3,400**	**$40,627**
1st GNWT Contribution Agreement ($20 million)	$14,219	$5,781		$20,000
2nd GNWT Contribution Agreement (up to $24 million)		$17,227	$3,400	$20,627
Total	**$14,219**	**$23,008**	**$3,400**	**$40,627**

CHAPTER 14

SUPPLEMENTARY INFORMATION

14.0 SUPPLEMENTARY INFORMATION

14.1 SIGNIFICANT CHANGES IN ACCOUNTING STANDARD, POLICIES AND PRACTICE

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14.2 SUPPORTING STUDIES

The following studies have been included;

14.2.1 Lead Lag Study

14.2.2 Amortization/Depreciation Study

14.2.1 Lead Lag Study

The purpose of the Lead Lag Study is to provide an analysis and documentation of the cash component of the working capital allowance. Generally, expenses occur in advance of the receipt of revenues, and therefore lead revenue collection. Working capital is required to pay operating expenses in advance of collecting revenues.

The provision of electric services is followed by the payment of expenses, which is then followed by the collection of the associated revenue. Expenses lag the provision of goods and services while revenue lags both the provision of service and the payment of expenses. Generally, the payment of expenses occurs after the goods or service has been provided, but in some cases, expenses occur in advance of receiving the goods or service. The lag is measured as the interval in days starting with the provision of the goods or service. There are two separate studies involved in the lead lag study, the operating lead lag and the GST lead lag. The operating lead lag is made up of the numbers of lag days in collection of revenue and the number of lag days in payment of operating expenses. The GST lead lag is analyzed separately as these amounts, while not representing revenues or expenses, do impact the Corporation's cash working capital.

Method

The weighted average operating revenue lag was arrived at by preparing an analysis of revenue accounts for the period of April 1, 2014 to March 31, 2015. The expense lags are by major expense category. For the expense lags, the 2001/03 Lead Lag study was used as a baseline and adjustments were made as required so the results of the category would be consistent with current operations. The GST lead lag also uses the previous 2001/03 Lead Lag study as a baseline adjusted in light of current conditions at the Corporation.

The average lag for revenues and expenses was calculated on a dollar-weighted basis. The number of lag days was multiplied by actual dollars to arrive at "dollar days". Dollar days allow a sample to be weighted so that all payments and receipts in the sample are equal. For example ten dollars paid one day after billing is equal to one dollar paid ten days after billing. Dollar days calculations were used in the previous lead lag studies and no changes were made to this methodology.

The total dollar days were then divided by the total dollars to calculate the weighted average lag days. The average lag as required was then further weighted by its corresponding actual revenue or expense for the 12-month period to determine the overall lag.

Calculation of Revenue Lag

The utility revenue lag was measured in three (3) ways:

1. Consumption - the number of days between initial consumption of energy and when the customers' meters were read;
2. Billing - Time between when the meters were read and when the customers were billed; and
3. Payment - Time between when the customers were billed and when the payment was received.

Consumption Lag

To calculate the consumption lag for customers it was assumed that the utility's services are utilized uniformly throughout each month. The average consumption lag would be the midpoint of the consumption period. It is the Corporation's policy to read accounts on a monthly basis therefore the consumption lag is equal to 365 days/year divided by 12 months/year, further divided by 2 to calculate the average or midpoint for a consumption lag of 15.21 days.

Billing Lag

To establish the billing lag for customers a comprehensive analysis of all utility revenues billed and collected through the Corporation's billing system for the 2014/15 fiscal year was performed. Over one hundred thousand billing records were included in the study, which is equal to approximately 89% of the total population.

The accounts receivable balances for the bills were converted to dollar days by taking the balance and multiplying by the billing lag (in days) for each bill. The billing lag was

computed by taking the difference between the date of the bill and the date of the meter read.

To compute the billing lag by customer type the sum of the dollar days by customer type was then divided by the total amount billed by customer type. This results in is an average billing lag by customer type. To derive an overall billing lag the billing lag by customer type was weighted according to the total revenue by customer type.

Payment Lag

To establish the payment lag a process very similar to calculating the billing lag was used. Using the same billing data, the accounts receivable balances for the bills were converted to dollar days by taking the balance and multiplying by the payment lag (in days) for each bill. The payment lag was computed by taking the difference between the date of the bill and the date of payment of the invoice.

To compute the payment lag by customer type the sum of the dollar days by customer type was then divided by the total amount billed by customer type. This results in an average payment lag by customer type. To derive an overall payment lag the payment lag by customer type was weighted according to the total revenue by customer type.

Calculation of Expense Lag

For the current 2016/19 Lead Lag study the expense lags from the previous 2001/03 study were used as a baseline and adjustments were made as required. The current operations of the Corporation have not changed in a significant way from this previous

study and the results are still valid. The current expense lags were adjusted to reflect current operations, as required. Where the previous study's results are being utilized this has been indicated. The following outlines the various major expense categories of the Corporation and how the lag days for the expense category were derived.

Fuel

The lag estimate for fuel is based upon the results of the previous 2001/03 lead lag study. The lag estimate of 54.94 days was selected as it is reasonably reflective of current operations and produces a favourable result for customers. The previous 2012/14 GRA estimated a 45.00 day lag for fuel. The current study has increased this lag by 9.94 days as per Table 14.2.1. This increase in lag was applied to the average 2014/15 fuel expenses per day, which decreases the Corporation's cash working capital requirements by $0.777 million as indicated in Table 14.2.2. Applying the current return on Rate Base to the decrease in cash working capital results in a decrease in Revenue Requirement of approximately $0.053 million as per Table 14.2.3.

Table 14.2.1

2012/14 Fuel Lag Compared to 2016/19

Expense Type	Lag Days 2016/19	Lag Days 2012/14	Lag Days Increase
Fuel and Lubricants	54.94	45.00	9.94

Table 14.2.2

2016/19 Fuel Lag Change: Cash Working Capital Impact

Expense Type ($000's)	2014/15 Actual	2014/15 Per Day	Lag Days Change	Cash Working Capital Decrease
Fuel and Lubricants	28,514	78.12	9.94	(777)

Table 14.2.3

2016/19 Fuel Lag Change: Revenue Reduction

Expense Type ($000's)	Cash Working Capital Decrease	Return on RateBase (%)	Revenue Requirement
Fuel and Lubricants	(777)	6.88%	(53)

Supplies and Services

In previous studies, the supplies and services category has been split out into supplies and services (other) and consultants and contractors. In this study, these results have been combined into total supplies and services. To compute the lag days for this category the results of the previous 2001/03 study was used. The suppliers and service providers the Corporation currently utilizes have not changed in a significant way from the previous study and the results remain valid. Using 2015 actual costs and a dollar days calculation, the lag days from the previous study were used and a weighted value computed, as set out in Table 14.2.4. Based on this new categorization of Supplies and Services the revised lag days are 48.66.

Table 14.2.4

Supplies and Services Lag Day Calculation

Expense Type ($000's)	2014/15 Actual	Lag Days	Weighted Average Cost
Other Supplies and Services	6,064	55.41	336,006
Consultants and Contractors	6,527	42.39	276,680
Supplies and Services	**12,591**	**48.66**	**612,686**

Travel and Accommodation

For this category the results of the previous study were used. The Corporation's travel and accommodations policies have largely remained the same and there have been no significant changes in this area. The previous study results are still valid; the lag for this category is 14.89 days.

Insurance

Under this category, the Corporation has considered only the payments for insurance policies such as property, boiler and machinery, etc. The property insurance for the Corporation was prepaid on Dec.11, 2015 with coverage starting Dec. 1, 2015 and lasting until Nov. 30, 2016. Using the assumption that the insurance coverage benefit is equally consumed throughout the year, the consumption lag would be approximately 182.5 days (365/2=182.5). The balance of the lags was calculated by reviewing the payments to the Corporation's insurance broker for non-property insurance. The overall lead for insurance was 158.93 days.

Salaries and Wages

Salaries and wages were considered to have two components:

1. Net cash payment to employees including overtime; and
2. Remittance of statutory and other payroll deductions.

Regular salaries and wages, overtime, and benefits such as local differential payments and northern allowances, are paid 14 days after the last day worked in the pay period; therefore the average lag was determined to be 21 days [14 + 14/2].

For the remittance of statutory and other payroll deductions such as CPP, EI, Superannuation, Union Dues, and Insurance (e.g. Life, Disability) the results of the previous lead lag study were used. There has been no change in the types of deductions that are made and their timing. Payroll deductions from employees for income tax, CPP, and EI contribution were paid to the Receiver General for Canada on the due dates required by law. The average lag for all deductions was 18.20 days.

Using 2015 actual costs and a dollar days calculation, the lag days for each salary component were used and a weighted value computed (see Table 14.2.5). The combined overall lag for Salaries and Wages was 20.25 days.

Table 14.2.5

Salaries and Wages Lag Day Calculation

Expense Type ($000's)	2014/15 Actual	Lag Days	Weighted Average Cost
Salaries, Wages, and Overtime	17,923	21.00	376,383
Employee Benefits	6,564	18.20	119,465
Total Salaries and Wages	**24,487**	**20.25**	**495,848**

Goods and Services Tax

There are two components in the calculation of GST lag. To the extent that GST is received from customers before it is remitted to the Federal government the GST provides a source of funds to the Corporation. Payment of GST is made when suppliers invoices are paid and these amounts are not recovered from the Federal government until the filing of the input tax credit claim and, in the case of a net refund, the receipt of the cash.

Net GST Remittance Lag

The lag for collecting GST from customers is the same as the overall revenue lag of 43.55 days less the consumption to billing lag of 15.21 days, as the amounts are not due until they are invoiced, for a net lag of 28.34 days. The GST remittance lag is the difference between the billing dates and when the GST is remitted to the Federal government. GST is due 30 days following the month the taxable amount was invoiced. The GST remittance lead from the previous study was 34.46 days. The resulting net GST lead on revenue, therefore, is arrived at by netting the GST remittance lead of 34.46 days against the revenue lag of 28.34 days. This net remittance lag is 6.12 days.

GST Lag on Purchases

The second component refers to the GST expenditure lag. It arises from GST paid on operating expenses incurred by the Corporation in providing service.

For this component the results of the previous study were used. The net GST lag was estimated at 12.66 days.

14.2.2 Amortization/Depreciation Study

A copy of the Depreciation Study is attached to this Application in Appendix A.

14.3 PERFORMANCE METRICS

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14.4 BUSINESS CASES

Copies of the Business Cases are attached to this Application in Appendix B.

14.5 REPORTS OF FINANCES AND OPERATIONS

Reports of Finances and Operations for 2013/14 and 2014/15 were sent to the PUB on May 20, 2016.

14.6 RELIABILITY AND QUALITY OF SERVICE

A Copy of the Reliability and Quality of Service report is attached to this Application in Appendix C.

14.7 BUSINESS CONTRACTS

The following is a description of the major contractual agreements of the Corporation for the supply of goods and services. Major agreements for the purpose of this section include long-term agreements greater than one year and exclude contracts for capital projects. Contracts for capital work are project specific and the costs are included in each capital project.

1. Fuel Services Division Agreement – The main fuel supplier for the Corporation is the Fuel Services Division (FSD), previously known as the Petroleum Products Division (PPD), a division of the GNWT Department of Public Works and Services. The Corporation has a main agreement with FSD with memorandum of understandings for each of the plants which are supplied. This is a long-standing

agreement. The Fuel Services Division supplies diesel fuel to most of the communities in the thermal zone and diesel for backup facilities in the Snare and Taltson zone. The price of fuel is set at the community level and based upon the market price of fuel, the cost of freight, and an administration fee.

2. Northwest Territories Energy Corporation (NTEC) Liquefied Natural Gas Agreement – The Corporation entered into an agreement on October 31, 2013 with NTEC (03) to have liquefied natural gas (LNG) supplied to the power plant in Inuvik. The price of LNG under this agreement was based upon NTEC's cost to acquire and transport LNG to the Inuvik plant and an administrative fee. NTEC was a subsidiary of the GNWT Department of Public Works and Services (PWS). As of April 1, 2015 NTEC functions has been absorbed into the PWS and the existing LNG agreement has been transferred with no interruption of service.

3. Aklavik Diesel Fuel Supply Agreement – The Corporation has an exclusive diesel fuel supply arrangement with Beaufort Delta Petroleum to provide diesel fuel to the Aklavik power plant. This agreement contains a confidentiality clause and the key terms of this agreement cannot be disclosed.

4. Norman Wells Power Purchase Agreement – The Corporation has an agreement with Imperial Oil Resources N.W.T. Limited to purchase power from Imperial's power plant in Norman Wells. Imperial established a plant in Norman Wells to provide power for their existing facilities. The Imperial plant has some excess capacity which the Corporation has been able to purchase on favourable terms. As part of this agreement, the Corporation purchases power from Imperial wholesale and the then distributes power to customers in and near Norman wells via its distribution lines.

5. Wajax Power Systems Agreement – The Corporation has a comprehensive arrangement with Wajax Power Systems to provide engines, generators, parts, accessories technical support, training, and other ancillary services, for the Detroit Diesel engine fleet. This agreement was signed on June 1, 2013 and has a three year term with a semi-annual review. The agreement can be terminated by mutual agreement or with six month of notice provided by either party.

6. Water Survey of Canada Agreement – The Corporation has an agreement with the Water Survey of Canada, which is a branch of Environment Canada Meteorological Service to operate and maintain eleven hydrometric stations. The stations are located in the Snare River, Talston River, and Yellowknife River basins. The most recent agreement was for the previous fiscal year. This has been an ongoing arrangement and is renewed annually.

14.8 SNARE FORKS MAJOR PROJECT PERMIT

A copy of the Snare Forks Major Project Permit is attached to this Application in Appendix D.

14.9 INTELLIGENT METERING MAJOR PROJECT PERMIT

A copy of the Intelligent Metering Major Project Permit is attached to this Application in Appendix E.

14.10 NORMAN WELLS NEW PLANT MAJOR PROJECT PERMIT

A copy of the Norman Wells New Plant Major Project Permit is attached to this Application in Appendix F.

14.11 BLUEFISH POST PROJECT REPORT

A copy of the Blue Fish Post Project Report is attached to this Application in Appendix G.

14.12 COLVILLE LAKE PLANT POST PROJECT REPORT

The Colville Lake project was commissioned in late 2015/16 and accordingly the Corporation will complete and submit a post project report in 2016/17.

14.13 TERMS & CONDITIONS OF SERVICE

A blacklined copy of the Terms and Conditions of Service is attached to this Application in Appendix H.

14.14 GLOSSARY OF TERMS

Amortization

Represents the benefit the customers get each year from the use of plant and equipment. The benefit is calculated as a portion of the cost of the plant and equipment depending on the estimated number of years that it will be of use to the customer.

Capacity

The load at which a generation unit, generation station, or other electrical apparatus is rated either by the user or by the manufacturer.

Capital Expenditures

Cost of construction, additions, acquisition and betterments of utility plant facilities.

CEO

Chief Executive Officer

CFO

Chief Financial Officer

Construction Work In Progress (CWIP)

Fixed assets under construction by a regulated entity for its future use.

Consumer Price Index (CPI)

A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption

Use of electrical energy over time, typically measured in kilowatt-hours.

Corporation

The Northwest Territories Power Corporation.

Cost of Service

The total cost to the Corporation of providing energy and related utility services to its customers. Includes the cost of invested capital as well as operational costs.

Customer

Individual or entity that takes service from the utility. Similar customers are grouped into Customer classes. Customer classes are usually differentiated from each other in terms of the level and type of service they require from the utility.

Customer Class

A distinction between users of electrical energy.

Deferred Cost

Represents the benefit the customers get each year from the use of non-tangible assets that have a future benefit in excess of one year and are recorded as a capital asset.

Degree - Day

A unit measuring the extent to which the outdoor mean daily temperature falls below or rises above an assumed base. The base is normally taken at 18°C for heating and cooling unless otherwise designated. One degree-day is counted for each degree of

deficiency below (for heating) or excess over (for cooling) the assumed base, for each calendar day on which such deficiency or excess occurs.

Demand

The rate at which electric energy is delivered to or by a system, part of a system or a piece of equipment; expressed in kilowatts, kilovolt-amperes, or other suitable unit at a given instant or averages over any designated period of time. The primary source of demand is the power-consuming equipment of the customers.

Demand Side Management (DSM)

Techniques designed to be used by the customer to reduce their consumption of energy.

Direct Cost

A cost incurred for one specific customer or customer classes.

Distribution

The act or process of distributing electric energy from convenient points on the transmission or bulk power system to the consumers.

Distributed Generation

Electric generation facilities connected to any of the Corporation’s distribution systems.

Distributed Resource

Sources of real electric power that are not directly connected to the Corporation facilities.

Distribution Line

One or more circuits of a distribution system on the same line of poles or supporting structures, operating at relatively low voltage as compared with transmission lines.

Efficiency

Engine efficiency; the amount of kilowatt-hours produced per litre of fuel.

Emissions

Greenhouse gas emissions produced by diesel generation. Methane (CH_4) and Nitrous Dioxide (N_2O) gases are converted into Carbon Dioxide (CO_2) equivalent.

Energy

a) Electricity;

b) Heat which is supplied through a district heating system by hot water, hot air or steam; manufactured gas, liquefied petroleum gas, natural gas, oil or any other combustible material which is supplied through a pipeline or any other distribution system directly to a customer; or

c) Any prescribed matter pursuant to a regulation under the Northwest Territories Power Corporation Act.

Equity

The portion of the Corporation's total capital contributed by the owner, as distinct from borrowed capital, and normally represented by shares and retained earnings of the Corporation.

FERC

Federal Energy Regulatory Commission

Firm Power

Power or power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions.

Fiscal Year

The General Rate Application considers the fiscal year of April to March, which is consistent with the Corporation’s financial reporting practices. For the three Test Years 2016/17 represents the year April 1, 2016 to March 31, 2017.

Fixed Asset

Tangible property used in the operations of regulated business, but not expected to be consumed or converted into cash in the ordinary course of business.

Fixed Costs

Those costs which, in the short run, do not vary with kilowatt-hours produced or sold, or number of Customers served.

General Service

Customer Classification for service other than Residential, Industrial, Wholesale, or Street Lighting.

Generation

This term refers to the act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kilowatt-hours (kWh).

Genset

A generation set; matched set of engine and generator.

GNWT

The Government of the Northwest Territories

Gross Plant in Service

Represents the accounting cost of all regulated assets current used in ordinary course of business.

Heating Degree Day (HDD)

A unit measuring the extent to which an outdoor dry-bulb temperature falls below an assumed base (18°C). One HDD is counted for each degree of deficiency below the assumed base, for each calendar day on which such a deficiency occurs.

Indirect Cost

A cost incurred for two or more customers or customer classes.

Industrial

Sales to businesses primarily engaged in resource exploration or development, manufacturing, fabrication, or marine or air transportation.

Installed Capacity

The total Generation Capacity installed in a plant.

Interruptible Power

Power made available under agreements which permit curtailment or cessation of delivery by the supplier.

Interruptible Rate

A rate normally covering reduced pricing for a supply of electricity that can be interrupted at the utility's option, either instantaneously as required or with advanced notice.

Interconnection Guideline

The criteria and technical requirements for interconnection of a distributed resource operating in conjunction with the Corporation’s facilities.

Kilowatt (kW)

The measure of electrical capacity required by the customer at any instantaneous moment. The kWh equates to power. One kilowatt equals 1,000 watts. One megawatt (MW) equals 1,000 kWs.

Kilowatt-hour (kWh)

Basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Line Losses

Kilowatt-hours and kilowatts lost in transmission and distribution lines under specified conditions.

Load

The amount of electric power delivered or required at any specific point or points on a system. Load originates primarily at the power-consuming equipment of customers.

Load Forecast

An estimate of electrical demand or energy consumption at some future time.

Local Area Network

A network that connects computers that are close to each other, usually in the same building, linked by a cable.

Loss of Energy Expectation (LOEE)

The expected energy not served as a result of system deficiency, generally expressed in kWh or MWh.

Loss of Load Expectation (LOLE)

The expected number of hours in a specified period when a loss of load occurs.

Losses

Refers to the energy that is lost through transformation, transmission, and distribution.

Load Factor

The ratio of the average demand over a designated period of time to the maximum demand occurring in that period.

Loss of Load Probability

A measure of the probability that system demand will exceed capacity during a given period, often expressed as the long-term average of expected number of days per year.

Maintenance Expense

Direct and indirect expenses including labour, material and others incurred for preserving the operation efficiency or physical condition of the utility plant used for power production, transmission and distribution of energy, and administrative and general operations.

NTPC

The Northwest Territories Power Corporation

NWT

Northwest Territories

O & M

Operating and Maintenance

Operating Expenses

Direct and indirect expenses, including labour, materials and others, incurred in the production of electricity.

Outage

The period during which a generation unit, transmission line, or other facility is out of service.

Forced Outage - The shutting down of a generating unit, transmission line, or other facility, for emergency reasons.

Scheduled Outage - The shutting down of a generating unit, transmission line, or other facility, for inspection or maintenance in accordance with an advance schedule.

Peak Load

The highest demand, measured over an interval of 15 or 30 minutes, on an electrical system during some period. As used in the forecast, peak load denotes the highest demand during the fiscal year.

Plant

Means a facility or facilities for the generation, transmission, transformation, distribution, delivery, supply or control of energy or for the distribution, delivery or supply of water and sewerage services and includes the site of the facility or facilities, and all land, water, rights to use water, buildings, works, machinery, installations, materials, transmission lines, distribution lines, pipelines, furnishings and equipment, plant in construction, stores and supplies acquired, constructed or used or adapted for or in connection with the facility or facilities.

Power

The rate of generating, transferring, or use of electric energy, with respect to time, usually expressed in kilowatts (kW).

Programmable Logic Control (PLC)

Automates the running of diesel engines. Ensures efficiency by automatically matching the engine(s) to the load as it fluctuates throughout the day.

PUB

The Public Utilities Boards of the Northwest Territories.

Rate Base

The property of the Corporation used or required to be used to provide service to the public within the Northwest Territories.

Rate Hearing

The procedural process used by a regulatory authority so that an utility company may present and justify its need for rate changes.

Rate of Return on Equity

An amount equal to the rate of return on equity earned by other utilities in situations of similar risk to that of the Corporation.

Rates

The prices at which regulated services are provided.

Regulated

Aspects of the Corporation’s business subject to regulatory (PUB) approval.

Reserve Capacity

The extra generation capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: first, in case of unexpected breakdown of generating equipment, second, in case the actual peak load is higher than the forecast.

Residential

Single family residences or an individual apartment where electrical service is provided through one meter, provided that the residence or apartment is not used for Industrial, Wholesale or General Service purposes.

Residual Heating System

Residual heat recovery involves capturing some of the excess heat from the diesel engines and using it for space heating in buildings. The heat supplements the existing oil-fired boiler systems of the connected buildings, thereby reducing the amount of heating oil consumed by the building system.

Revenue Requirement

The revenue level necessary to meet the cost of providing service to the utility's customer.

RFID

Reserve for Injuries and Damages

Station Service

The electric energy used by the Corporation in the course of business.

Supervisory Control and Data Acquisition (SCADA)

Equipment that allows the remote and automated operation of generating units. SCADA also makes the collection and retrieval of load data possible.

Transform

The conversion of electric energy from high-voltage into low-voltage; completed through the use of transformers.

Transmission

The act or process of transferring electric energy in bulk from the point of generation to the point of transformation for distribution.

Variable Costs

Costs, such as fuel, that vary with the amount of electric energy supplied, or number of Customers served.

Water License

The regulatory approval permitting the Corporation to utilize water for its operations.

Wholesale

A customer, sales and revenue classification covering electric energy supplied to other electric utilities for resale to ultimate customer.